PB81-236127

Proceedings of the Joint Symposium on Stationary Combustion NOx Control. Volume II: Utility Boiler NOx Control by Combustion Modifications

(U.S.) Industrial Environmental Research Lab.
Research Triangle Park, NC

Prepared for

Electric Power Research Inst.
Palo Alto, CA

Aug 81

U.S. Department of Commerce
National Technical Information Service
NTIS

PB81-236127

EPA-600/9-81-028b
IERL-RTP-1084a

Proceedings of the Joint Symposium on Stationary Combustion NO_x Control

Volume II

Utility Boiler NO_x Control

by Combustion Modification

Symposium Cochairmen
Robert E. Hall, EPA
and
J. Edward Cichanowicz, EPRI

Program Element No. N130

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, D.C. 20460
and
ELECTRIC POWER RESEARCH INSTITUTE
3412 Hillview Avenue
Palo Alto, California 94303

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA 22161

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/9-81-028b	2. proceedings	3. RECIPIENT'S ACCESSION NO. PB81 236127
4. TITLE AND SUBTITLE Proceedings of the Joint Symposium on Stationary Combustion NO_x Control. Vol.II, Utility Boiler NO_x Control by Combustion Modification		5. REPORT DATE
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Symposium Cochairmen: Robert E. Hall (EPA) and J.E. Cichanowicz (EPRI)		8. PERFORMING ORGANIZATION REPORT NO. IERL-RTP-1084a
9. PERFORMING ORGANIZATION NAME AND ADDRESS See Block 12.		10. PROGRAM ELEMENT NO. EHE624
		11. CONTRACT/GRANT NO. NA (Inhouse)
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Proceedings; 10/6-9/80
		14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES EPA-600/7-79-050a through -050e describe the previous symposium. IERL-RTP project officer is R.E. Hall, Mail Drop 65, 919/541-2477.

16. ABSTRACT The proceedings document the approximately 50 presentations made during the symposium, October 6-9, 1980, in Denver, CO. The symposium was sponsored by the Combustion Research Branch of EPA's Industrial Environmental Research Laboratory, Research Triangle Park, NC, and the Electric Power Research Institute (EPRI), Palo Alto, CA. Main topics included utility boiler field tests; NOx flue gas treatment; advanced combustion processes; environmental assessments; industrial, commercial, and residential combustion sources; and fundamental combustion research. This volume relates to the use of combustion modification to control NOx emissions from utility boilers.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Flue Gases	Pollution Control	13B	
Combustion	Engines	Stationary Sources	21B	21K
Nitrogen Oxides		Environmental Assessment	07B	
Boilers			13A	
Tests			14B	
Assessments				

18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 535
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

(reverse is blank)

PREFACE

These preceedings document more than 50 presentations given at the Joint Symposium on Stationary Combustion NO_x Control held October 6-9, 1980 at the Stouffer's Denver Inn in Denver, Colorado. The symposium was sponsored by the Combustion Research Branch of the Environmental Protection Agency's (EPA) Industrial Environmental Research Laboratory-Research Triangle Park and the Electric Power Research Institute (EPRI). The presentations emphasized recent developments in NO_x control technology. Cochairmen of the symposium were Robert E. Hall, EPA, and J. Edward Cichanowicz, EPRI. Introductory remarks were made by Kurt E. Yeager, Director, Coal Combustion Systems Division, EPRI, and the welcoming address was given by Roger L. Williams, Regional Administrator, EPA Region VIII. Stephen J. Gage, Assistant Administrator for Research and Development, EPA, was the keynote speaker. The symposium had 11 sessions:

I: NO_x Emissions Issues
Michael J. Miller, EPRI, Session Chairman

II: Manufacturers Update of Commercially Available Combustion Technology
Joshua S. Bowen, EPA, Session Chairman

III: NO_x Emissions Characterization of Full Scale Utility Powerplants
David G. Lachapelle, EPA, Session Chairman

IV: Low NO_x Combustion Development
Michael W. McElroy, EPRI, Session Chairman

Va: Postcombustion NO_x Control
George P. Green, Public Service Company of Colorado, Session Chairman

Vb: Fundamental Combustion Research
Tom W. Lester, EPA, Session Chairman

VI: Status of Flue Gas Treatment for Coal-Fired Boilers
Dan V. Giovanni, EPRI, Session Chairman

VII: Small Industrial, Commercial, and Residential Systems
Robert E. Hall, EPA, Session Chairman

VIII: Large Industrial Boilers
J. David Mobley, EPA, Session Chairman

IX: Environmental Assessment
Robert P. Hangebrauck, EPA, Session Chairman

X: Stationary Engines and Industrial Process Combustion Systems
John H. Wasser, EPA, Session Chairman

XI: Advanced Processes
G. Blair Martin, EPA, Session Chairman

VOLUME II

TABLE OF CONTENTS

Page

Session II: Manufacturers Update of Commercially Available Combustion Technology

"Fossil Steam Generator NO_x Control Update," J. A. Barsin 1

"Current Developments in Low NO_x Firing Systems," D. J. Frey and T. Kawamura 26

"Development and Field Operation of the Controlled Flow/Split-Flame Burner," J. Vatsky 62

"An Evaluation of NO_x Emissions from Coal-Fired Steam Generators," R. A. Lisauskas and J. J. Marshall 104

Session III: NO_x Emissions Characterization of Full Scale Utility Powerplants

"Fireside Corrosion and NO_x Emission Tests on Coal-Fired Utility Boilers," E. H. Manny and P. S. Natanson 126

"NO_x Emissions Characteristics of Arch Fired Furnaces," T. W. Sonnichsen and J. E. Cichanowicz 176

"Combined-Cycle Powerplant Emissions," P. L. Langsjoen, R. E. Thompson, L. J. Muzio, and M. W. McElroy 207

"Relationship Between NO_x and Fine Particle Emissions," M. W. McElroy and R. C. Carr 245

Session IV: Low NO_x Combustion Development

"Commercial Evaluation of a Low NO_x Combustion System as Applied to Coal-Fired Utility Boilers," S. A. Johnson and T. M. Sommer 262

"Pilot Scale Evaluation of a Low NO_x Tangential Firing Method," J. T. Kelly, R. A. Brown, J. B. Wightman, R. L. Pam, and E. K. Chu 311

Page

"The Development of Distributed Mixing Pulverized Coal Burners," D. P. Rees, J. Lee, A. R. Brienza, and M. P. Heap 352

"The Development of a Low NO_x Distributed Mixing Burner for Pulverized Coal Boilers," B. A. Folsom, L. P. Nelson, and J. Vatsky 377

"Field Evaluation of Low Emission Coal Burner Technology on a Utility Boiler," E. J. Campobenedetto 414

"Operating Experience and Field Data of a 700 MW Coal-Fired Utility Boiler with Retrofit Low NO_x Staged Mixing Burners," K. Leikert and S. Michelfelder 456

"Japanese Technical Development for Combustion NO_x Control," K. Mouri and Y. Nakabayashi 483

FOSSIL STEAM GENERATOR NO_x CONTROL UPDATE

By:

Joseph A. Barsin
The Babcock & Wilcox Company
Barberton, Ohio 44203

ABSTRACT

Since the Second NO_X Control Seminar of 1978, much additional information has been collected concerning actual NO_X emissions from fossil fuel power plants equipped with B&W Dual Register Burners/Compartmented Windbox furnace systems for a wide range of both bituminous and subbituminous coals. These field results from actual units firing coal, oil and/or gas have demonstrated NO_X reductions of up to 60 percent compared to units without NO_X control. This presentation will show our controlled NO_X emission level experience and the present status of B&W's advanced NO_X control systems to meet the more restrictive NO_X emission levels expected in the future.

ACKNOWLEDGEMENTS

The author appreciates the assistance of Ed Campobenedetto and Gayle Hixson for their extensive work obtaining and reducing all of the NO_X data collected by our Results Engineering Section on the many units tested to date. In addition, I wish to thank Babcock-Hitachi in general and, specifically, Messrs. Kubota, Mimura and Takeyama of that organization for their assistance.

The 1971 federal New Source Performance Standards limited NO_X emissions for most fossil fuels for the first time. Prior to the federal controls, local air quality districts had established emission limitations in polluted areas. For example, Babcock & Wilcox instituted a NO_X reduction program in 1957 at the request of utilities firing gas and oil fuels in the south coast air quality district. The program led to successful application of two-stage combustion and a patent granted to B&W in 1959 for the process. This early work was followed by the selective use of gas recirculation to the burner to reduce peak flame temperatures and further reduce NO_X emissions. These approaches were successfully retrofitted to the larger California units in the late 1960s and early 1970s, resulting in up to 60 percent NO_X emission reduction.

In 1970, extensive work commenced on the development and application of a combustion system to limit NO_X emissions while firing pulverized coal. Previous to the New Source Performance Standards, our mission as designers was to maximize turbulence in the combustion zone, which would optimize carbon utilization and, thereby, reduce the furnace residence time required to obtain acceptable carbon utilization. Such an approach resulted in extremely high input burner zones, small furnaces with high heat release rates, and the application of our turbulent cell burner. This optimized combustion system successfully obtained the goal of maximum carbon utilization and, unfortunately, generated high levels of nitrogen oxide emissions. The kinetics involving the air/nitrogen to NO_X transformations were understood well enough from our gas and oil experience to provide direction in developing a new combustion system that would limit free oxygen available in the flame zone and reduce peak flame temperatures.

Our thoretical combustion model indicated what we wanted to achieve in a burner design to inhibit NO_X formation and at the same time continue to maximize carbon utilization. We postulated that a fuel rich jet mixing with secondary air at a controlled rate would reduce the peak flame temperature and control the oxygen availability. This model was utilized to develop the Dual Register Burner. The hardware development of that concept indicated that a spreader device of some type was required to maintain homogenous particle distribution and avoid pitfalls similar to those encountered in operation without impellers. Also required was some means of balancing coal line pressure drop variations caused by different

lengths of coal pipes being fed by the same pulverizer.

The mixing device selected initially was the venturi. While subjected to erosion, the venturi was not subjected to high temperatures and therefore would not coke or fall off. The overall primary air/fuel flow to each burner was maintained by a permanent, calibrated orifice located in each coal line between the pulverizer and the burners. The orifices were sized to equalize the calculated line pressure drops for the various coal pipe lengths from each mill.

The remaining combustion air (secondary air) was introduced through two concentric air zones which surround the coal nozzle. The air flow to each air zone was independently controlled through an outer air zone register and inner air sleeve.

In addition to a mixing device (venturi diffuse) to obtain proper particle distribution, some means had to be provided on the air side to control the flame front location. Spin vanes were added to the inner air zone to control axial/tangential secondary air velocity. The optimum vane position was found to be a function of the fuel being fired.

These two additions to the model resulted in the "Dual Register Pulverized-Coal Burner" (Figure 1).

By controlling the mixing of coal and air in a Dual Register Burner, the combustion process can be initiated at the burner throat and the zone of completion can be varied in the furnace chamber. This method of delayed combustion reduces combustion intensity and acts to reduce peak flame temperatures at each burner. Thus, the peak temperature in the furnace is lowered, minimizing the thermal conversion of combustion air nitrogen to NO_x. In addition, a larger percentage of the furnace zone water-cooled surface is utilized during the combustion process to further lower the peak temperature in the flame. Finally, through controlled fuel and air mixing, the oxygen availability is minimized during the process, thereby reducing fuel nitrogen conversion.

The Dual Register Burner lowers NO_X by delaying combustion, not by staging. Previous work on pulverized-coal firing has shown that two-stage combustion is an effective method for NO_X reduction.[1] However, in reviewing overall unit performance, the Dual Register Burner has the following benefits over staging techniques:

1. The furnace is maintained in an oxidizing environment to minimize slagging and reduce the potential for furnace wall corrosion when burning high sulfur bituminous coals.
2. More complete carbon utilization occurs through better air/coal mixing in the furnace.
3. Lower oxygen levels are required when total combustion air is admitted through the burners rather than above the burner zone.

RETROFIT

A retrofit system for the E. C. Gaston plant, Southern Electric Generating Company, demonstrated NO_X reductions of up to 50 percent, unstaged, compared to levels obtained with the high turbulence circular burners which were replaced. The correlation of heat available per square foot of adjusted burner zone surface, which had been developed and utilized for commercial commitments on gas and oil fuels, has been utilized for coal with good results. In fact, the prediction curves generated by our NO_X experiments on the retrofit at the E. C. Gaston unit provide the basis upon which all NO_X emission guarantees were granted. Initial retrofit data obtained in 1972, and retested in 1974 and 1976, provided the only projection of expected NO_X emissions with the new burner until units equipped with the new system actually went into commercial operation. The first of these New Source Performance Standards designs was declared commercial late in 1975, the second and third in 1976, and at present we have 26 operating pulverized-coal-fired units that were sold to meet the New Source Performance Standards. Data obtained from 24 units tested correlate extremely well with the projections generated by the Dual Register Burner retrofit at the Gaston plant. Presently, we have 1800 burner years of experience with the Dual Register Burner system. Modifications have been made to improve primary air/coal mixing and decrease pressure drop in the primary air system, improve the operability of the spin vanes, and change the manner in which

inner air is introduced from a swirl type assembly to a streamline sleeve type assembly. These functional improvements have been field tested both in test tunnels and in actual operating units and indicate a further gain in stability and NO_X reduction. Presently, 14,237 MW of New Source Performance Standard coal units supplied by Babcock & Wilcox are in service. Most of these units have been fitted with a complete combustion system for low NO_X, including the Dual Register Burner, the Compartmented Windbox and larger furnaces (Figure 2).

PRESENT PRACTICE

The 1979 New Source Performance Standards promulgated on June 11, 1980, further reduced NO_X emissions requirements for bituminous coal to 0.6 lbs of NO_X per million Btu input and for subbituminous coal to 0.5 lbs of NO_2 per million Btu input. In addition, most of the synthetic fuels coming from coal are limited to 0.5 lbs NO_X per million Btu input. These new reduced levels and the proposed research goals for 1985 implementation pose new challenges for the designers, manufacturers, and suppliers of low NO_X combustion systems. Figure 3 indicates the NO_X emissions measured on all of our bituminous-fired steam generators tested which were equipped with the low NO_X combustion system and indicates how their emissions relate to the New Source Performance Standards of 1979. The majority of units are meeting the new 0.6 level even though they were designed to meet the old 0.7 level. However, new designs must be developed to provide some operating margin between the regulated limit of NO_X emissions and the actual expected level of NO_X emissions and insure that some operational flexibility is available. Figure 4 indicates our experience with units equipped to meet New Source Performance Standards while firing subbituminous coal and compares those levels to the new regulations. In all cases except one, units designed to meet the 0.7 former standard are meeting or exceeding the new standard of 0.5. The one exception, operating at high levels of excess air, does exceed the design standard of 0.7. We anticipate a further tightening of the subbituminous New Source Performance Standards and, once again, are developing systems to further reduce NO_X emissions on these fuels.

FUTURE WORK

Previous efforts successfully resulted in NO_X reductions of 50 percent from uncontrolled emission levels. Future development (Figure 5) currently under way is expected to result in 85 percent reductions in NO_X emissions from uncontrolled levels. The most developed of these systems, the Low NO_X Combustor (LNCS), conceived by B&W and funded jointly by EPRI and B&W, is a first step in the second generation combustion modification approach to NO_X reduction. The LNCS is a deep staging approach with stoichiometry held at the 65 to 75 percent range in the flame zone. The industry has been and will continue to be concerned with applying two-stage concepts to pulverized-coal containing high iron and greater than 2 percent sulfur levels.[2] Concern within B&W is based upon many years of witnessing uncontrolled furnace corrosion resulting from localized reducing atmospheres. Our position is that coals with high iron and sulfur are not suitable for classical two-stage combustion in the generally accepted method where a portion of the secondary furnace is subjected to reducing conditions and, thereby, potential corrosion. The LNCS approach is to isolate the reducing zone in small, controlled primary furnaces that could be either separately cooled to maintain low metal temperatures, made of a more corrosion resistant material, or designed to be replaceable. During the Second EPRI NO_X Control Technology Seminar in 1978, we reported[1] on results of the LNCS 4 million Btu Model. Now, the results of the 50 million Btu LNCS prototype are available. Model and prototype data correlate, and the feasibility study, now being finalized, will be submitted to EPRI at the end of October. One result reported in the feasibility analysis is that the total surface area required for heat transfer on the small individual primary furnaces, when added together, exceeded 30 percent of the total furnace surface area. Thus, the reducing zone isolation approach taken initially looses validity and an alternative approach has been substituted. The venturi furnace (Figure 6) is the present application of the Low NO_X Combustor concept. Advantages of that embodiment are that the components (such as ducts, windboxes, etc.), are all standard components, and the circulation system is standard. We can continue with known designs, such as the Dual Register Burner system, simply modified for adaptation into the LNCS. The next step in this development is to locate a field retrofit and obtain the associated external funding to cover the costs.

Our next step in low NO_X combustion modification development work would be the coupling of the "planetary burner concept," advanced by Babcock-Hitachi K.K. under CRIEPI funding, within the B&W LNCS. The overall stoichiometry of the combined concept is limited to approximately 70 percent in the primary furnace, but individual burner level stoichiometry is varied to achieve the planetary concept.[4]

The lowest rows of burners would operate at a stoichiometry of 0.8 to 0.85; the highest row of fuel input nozzles would operate at less than 0.50. The flames of the relatively fuel-lean lower levels pass through the extremely fuel-ruch reducing flame. Laboratory-scale demonstrations have indicated that NO_X formed in the lowest zone is decomposed as it passes through the reducing zone, with radical products such as NH, CH present reduced to N_2, CO_2, and H_2O. Above the primary combustion furnace, the secondary air ports increase stoichiometry to the 117 to 120 percent range required for total combustion of the fuel. This approach is similar to work reported by M. Heap, L. Muzio, and J. Beer, on char and fuel rich flame reduction.[5] Our emission goal for joining these two concepts is 110 ppm on coal. That combined concept has been tested recently on a full size utility unit located in New Mexico and initial data indicates promising reductions. Once again, the advantage of this type of combustion modification is that all of the components, circulation, and air duct configurations are standard and well-known to us as boiler designer and manufacturer and to our users. The area of greatest concern to us as designers is the mixing requirements at the secondary air introduction point above the primary combustion furnace. Our extensive experience in gas tempering port design, and the subsequent mixing in the furnace, used extensively to control furnace exit gas temperatures provides an excellent data base for us to utilize for the secondary air/flue gas mixing problem.

When only seven units had been tested in the field, we had excellent fuel nitrogen correlation with the resulting NO_X emissions and reported it in 1978. However, the more units we tested, the more varied were the nitrogens in those fuels and the more it became obvious that we were not able to correlate NO_X emissions with nitrogen in the fuel to any great extent.

To further reduce NO_X emissions with combustion modifications, we must better understand the fuel-nitrogen transformation. B&W has funded a program at its Alliance Research Center to further investigate various nitrogen level coals in an attempt to understand the parameters that influence percent conversion and continue to follow the work of Dave Pershing at the University of Utah[6] (Figure 7).

In the event that New Source Performance Standards are applied to existing units in localized non attainment areas, our successful retrofit on the E. C. Gaston plant indicates that it is possible to retrofit a combustion modification. Combustion modifications for NO_X reduction continue to be both fuel and site specific with each case requiring study. What modification was reasonable at the Gaston plant with the Dual Register Burner system might not be reasonable at another plant with a different fuel. As an alternative approach to reduce NO_X resulting from combustion modifications, B&W is under contract to the EPA to develop and apply their Distributed Mixing Burner concept to actual burner hardware which can be retrofitted to a U.S. utility unit.[5]

CYCLONE FURNACES

Cyclone units that have gone into service recently, but were not subjected to the New Source Performance Standards because none had been promulgated for North Dakota lignites, have achieved NO_X emission levels lower than those presently established by the New Source Performance Standards for Northern lignites. One new cyclone unit firing bituminous coal entered service during 1979 under the exemption granted to units firing at least 25 percent mine waste along with their base coal. The unit has been in operation for approximately 15 months. NO_X levels have not been measured because the client is complying with the requirement for using 25 percent mine waste and therefore, is exempt from the NSPS. One other 450 MW cyclone unit is scheduled for initial service early in 1981, firing a North Dakota lignite. Retrofits to existing units firing typical cyclone low fusion coal are not practical. The two-stage approach has been field demonstrated both at the Board of Public Utilities, Kansas City, and at Basin Electric's Leland Olds Unit #2 and showed significant NO_X reduction.

In the North Dakota lignite case, Basin Electric required extensive amounts of supplementary fuel to maintain flame temperatures high enough to insure tapping of the slag. The Board of Public Utilities experiment was successful while the Utility fired natural gas with NO_X reductions of 50 percent obtained under staged conditions. However, the base fuel for that Unit and the majority of all our cyclone furnaces utilize a fuel containing sulfur above 3 percent and iron above 18 percent in the ash. The combination of these elements in a molten slag pool, under reducing conditions, will result in immediate catastrophic loss of tube metal, subsequent to failures, and molten slag tapping through the floor of the cyclone and the steam generator. The application of two-stage techniques to cyclones firing typical cyclone suitable coal is, of course, possible and NO_X reductions would result; but the effects in an extremely short time would be catastrophic and we do not recommend the applications of two staging to cyclone furnaces (Figure 8).

The number of B&W New Source Performance Standards units firing oil in service in the United States is 17 and represent 6343 MW. Only one unit is presently under construction and none have been sold for domestic siting since 1974. The approach that has been utilized since 1959 involves classic two staging, gas recirculation through the windbox to reduce flame temperature. and BOOS (burners out of service) to optimize the staging and reduce the excess air levels required to maintain a clean smokstack. Initially, we investigated the effect of atomizer (mixer) design upon NO_X generation and, as expected, the atomizer producing the largest mean particle sizes produces the lowest NO_X. The design approach used for the Dual Register Coal Burner indicated that reduced peak flame temperatures and reduced turbulence are important criteria to incorporate in any combustion system to reduce NO_X (Figure 9).

The parallel flow burner was developed for oil and gas firing on New Source Performance Standards units because it did not depend upon turbulence to enhance the mixing and obtain acceptable burnout. The philosophy behind its design is streamline development and slow mixing coupled with better atomization. The independence of swirl requirements in this design make it possible to operate at extremely low excess airs over the

load range than had been possible with a swirl register assembly. There are approximately 2,000 burner years' experience with this approach, and when coupled with either gas recirculation or two staging, proves to be adequate to meet the New Source Performance Standards for both oil and gas.

In 1975, the Dual Register Oil Burner was developed and retrofitted to the Mandalay Unit 1 of the Southern California Edison system. Prior to the retrofit, utilizing two-stage combustion, it was possible to reach 340 ppm NO_X emissions on 0.3 percent N_2 at 2 percent O_2. Following the Dual Register Oil Burner retrofit and utilizing two-stage combustion, NO_X could be reduced to 210 ppm. It appeared possible to obtain up to a 35 percent reduction resulting simply from the combustion system utilized. The data also indicated no reduction at all at times and, therefore, the value of the retrofit and data are questioned. Additional retrofits were made at five Florida Power Corporation plants. Florida Power Corporation's concern centered around dust emissions and meeting the Performance Standards in Florida for 0.1 lbs of dust per million Btu input. The retrofitted burners met that level. We were permitted to test for NO_X emissions in 1980 and found levels of 200 ppm. No baseline NO_X levels are available. This level was obtained with full stoichiometric air to the burners (no staging, BOOS, or gas recirculation). Fuel nitrogens averaged 0.3 percent during the test series.

The first steam generator initially designed for the Dual Register Oil Burner is owned by Hawaiian Electric, designated as Kahe Unit 6, rated for 140 MW and currently in the prestart-up, stretchout period. Kahe Unit 5 is a duplicate unit which utilizes NO_X ports and circular (high turbulence) burners to meet an old state NO_X emission standard of 300 ppm, in effect at the time of its construction. Kahe Unit 6 is required to meet the federal New Source Performance Standards, and has been supplied with the Dual Register Oil Burner and no NO_X ports. We expect to better the NSPS for oil on this unit (Figure 10).

Babcock-Hitachi has developed the Dual Register Oil Burner one step further by injecting gas recirculation, undiluted, into the primary flame zone. They refer to this device as the Primary Gas Dual Register Oil and Gas Burner. This combustor, when coupled with staging and gas recirculation in the secondary air, has resulted in retrofit, NO_X emission levels as great as 85 percent below uncontrolled levels. Application of this combustor, coupled with a primary combustion furnace (LNCS) and operating in the planetary mode similar to what is presently under test for pulverized coal, will result in even lower commercially obtainable NO_X emissions than presently possible (Figure 11).

Research and Development plans for the 1980s will concentrate in three major NO_X areas. The first area is that of the fuel nitrogen correlations which govern the NO conversions on both solid fuels and liquid fuels. The second major area is to continue our successful efforts in combustion modification, retrofitting the LNCS and demonstrating total unit performance, and retrofitting the Distributed Mixing Burner and demonstrating total unit performance. The third area concerns Synthetic Fuels and includes SRC I and II, coal/oil mixtures, coal/water mixtures, chars, and other liquifaction products from coals. We have gained extensive experience with the SRC I and II fuels under EPRI and DOE funding for both the field retrofit portion and laboratory characterizations. In addition to the NO_X emissions, the burning, fouling, slagging and handling characteristics of these fuels must be classified to allow us to design combustion systems to handle them.

SUMMARY

Results from the 24 pulverized coal units tested to date show that the Dual Register Burner/Compartmented Windbox furnace system is an effective tool for NO_X emission control. NO_X levels 40 to 60 percent lower than those achievable with the high turbulance circular burner system are obtained through limited turbulence combustion. At the same time, carbon utilization has been maintained at levels comparable to those obtained

utilizing a high turbulence circular burner. Actual data collected for both fuel classes demonstrate NO_X emission levels to be within the 1978 NO_X limits established by the EPA New Source Performance Standards. Additional work in the area of combustion modifications, fuel nitrogen correlations and new fuel investigations must be continued to meet the anticipated tighter NO_X emission limitations expected over the next six years.

In the short term, through 1985, it is anticipated that we will have applied our Dual Register Burner/Compartmented Windbox furnace system to 150 utility steam generators with an approximated capacity of 67,500 MW. Typically, these units have generated half the NO_X they would have if the New Source Performance Standards of 1971 had not implemented emission controls. We are prepared with proven combustion modification retrofits to apply to units in non attainment areas on a base by base basis and plan to continue working with both EPRI and EPA to develop our lower NO_X concepts for commercial applications from combustion modifications in the late 1980s.

REFERENCES

1. Barsin, J. A. Pulverized Coal Firing NO_X Control. 2nd EPRI NO_X Control Technology Seminar. Denver, Colorado. November 8 & 9, 1978.

2. Manny, E. H. and P. S. Natanson. Fireside Corrison and NO_X Emission Tests on Coal-Fired Utility Boilers. Exxon Research and Engineering Company. In: Proceedings of the Joint Symposium on Stationary NO_X Control. October 1980.

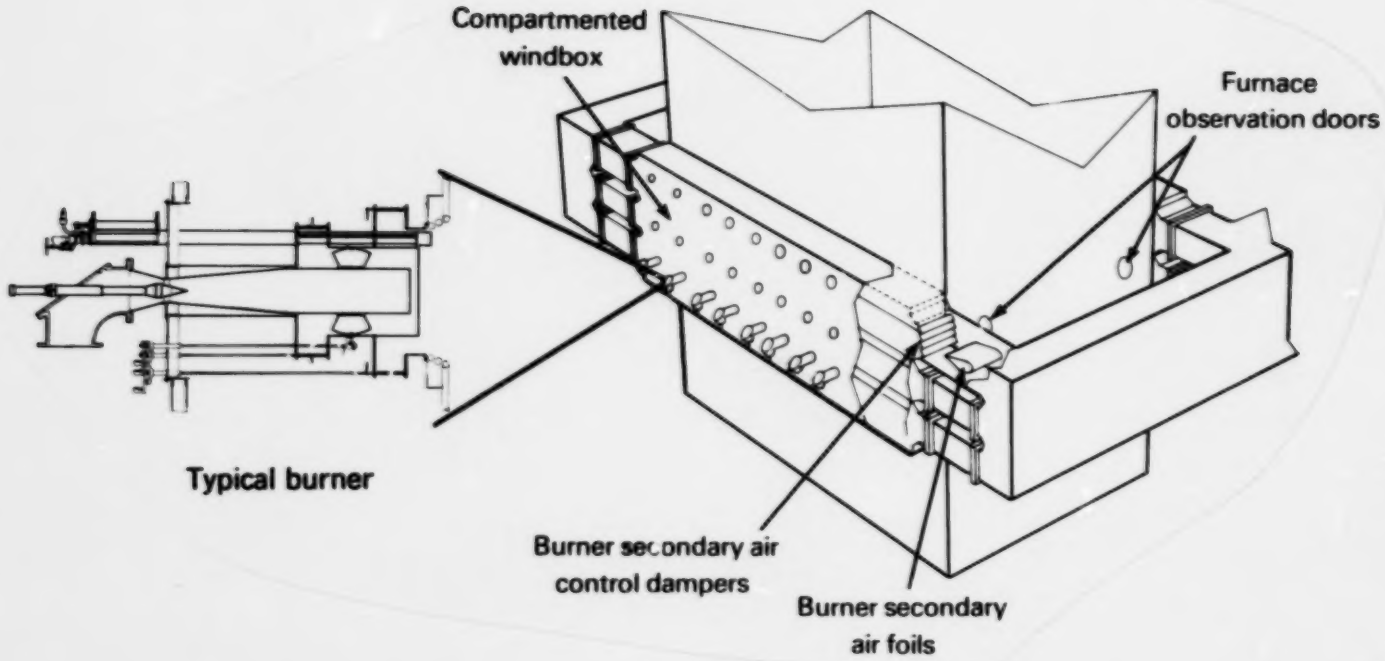
3. Johnson, S. A. and T. M. Sommer. Commercial Evaluation of a Low NO_X Combustion System as Applied to Coal-Fired Utility Boilers. The Babcock and Wilcox Company. In: Proceedings of the Joint Symposium on Stationary NO_X Control. October 1980.

4. Babcock-Hitachi Internal Information Exchanges. 1979 and 1980.

5. Campobenedetto, E. J. Field Evaluation of Low NO_X Coal Burners for Utility Boilers. The Babcock & Wilcox Company. In: Proceedings of the Joint Symposium on Stationary NO_X Control. October 1980.

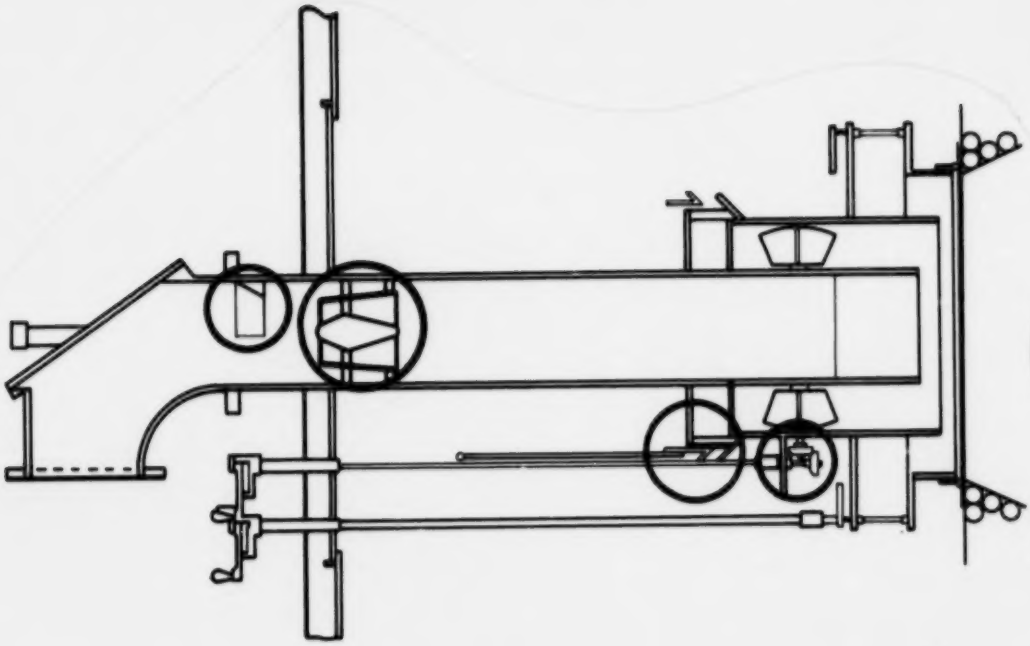
6. Song, Y. H., J. M. Beer and A. R. Sarofin. Fate of Fuel Nitrogen During Pyrolysis and Oxidation. M.I.T. In: Proceedings of the Second Stationary Source Symposium. July 1977.

7. Chen, S.L., M. P. Heap, D. W. Pershing, R. K. Nihart and D. P. Rees. Fate of Coal Nitrogen During Combustion. In: Proceedings of the Joint Symposium on Stationary Combustion NO_X Control. October 1980.

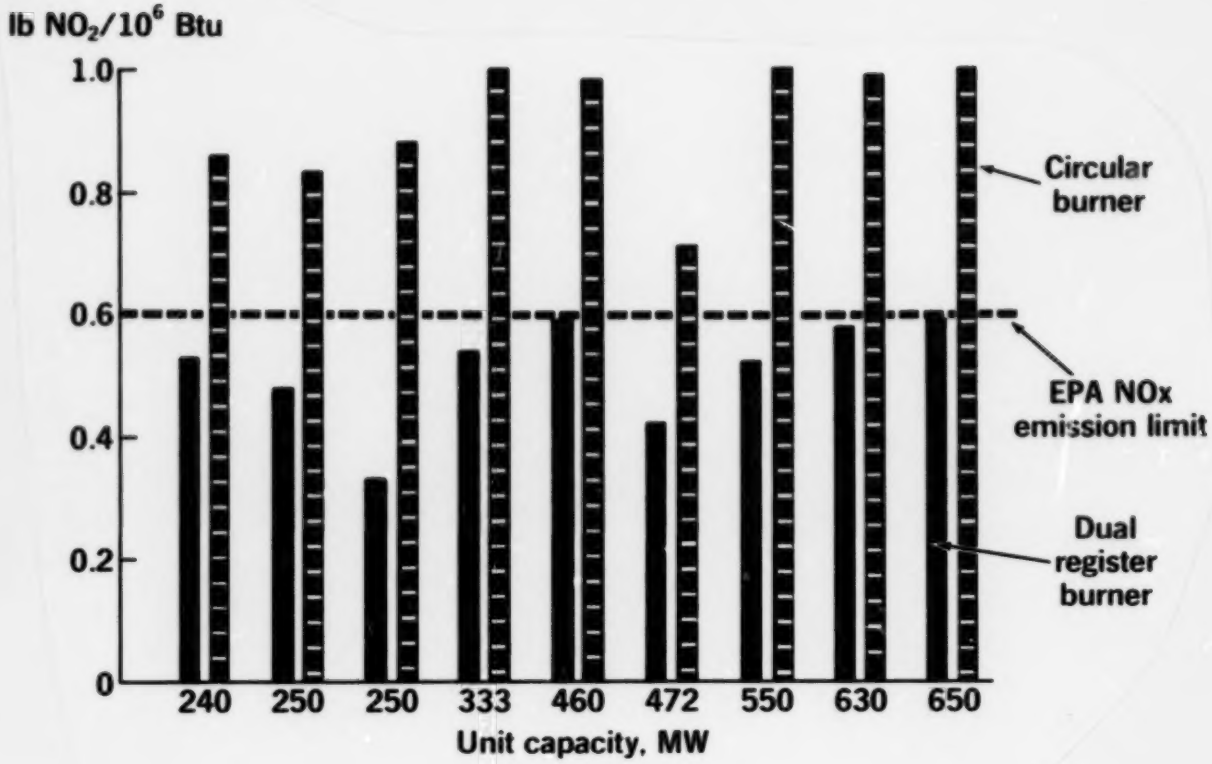


Dual Register Burner/Compartmented Windbox system

Figure 1

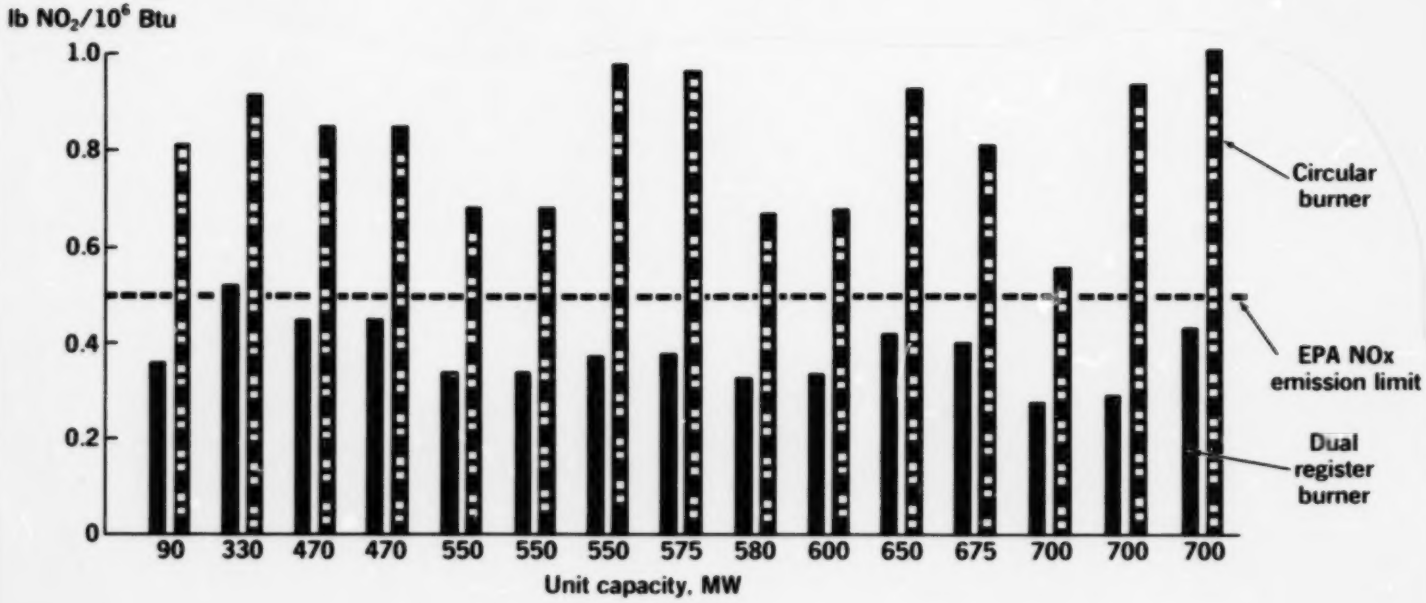


Dual Register Burner
Figure 2



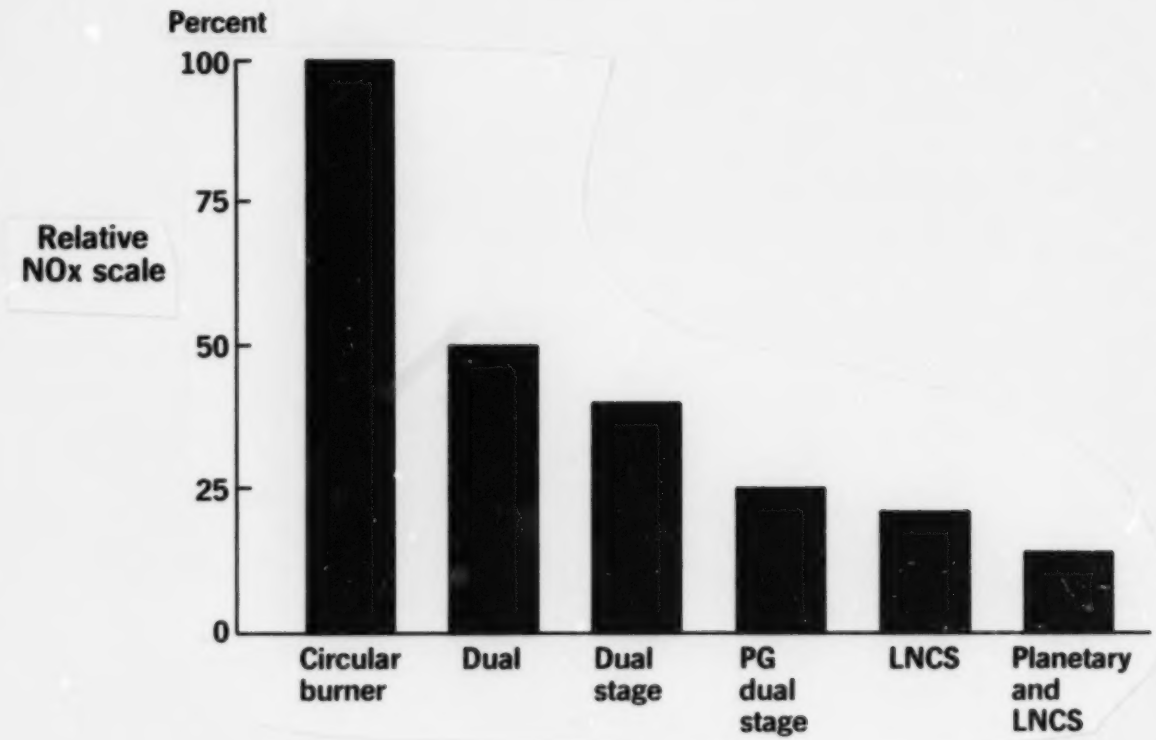
Comparison of NO_x emissions from circular burners and Dual Register Burners with bituminous coal

Figure 3



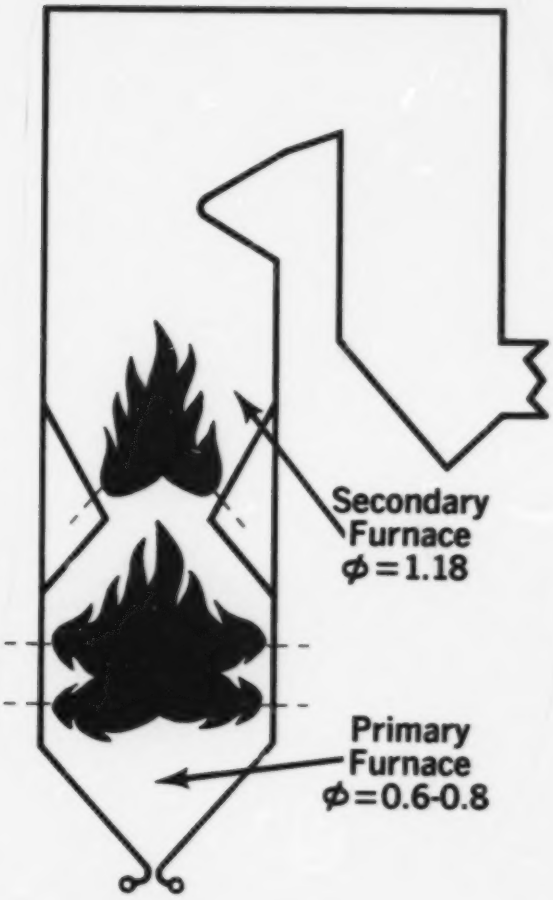
Comparison of NOx emissions from circular burners and Dual Register Burners with subbituminous coal

Figure 4



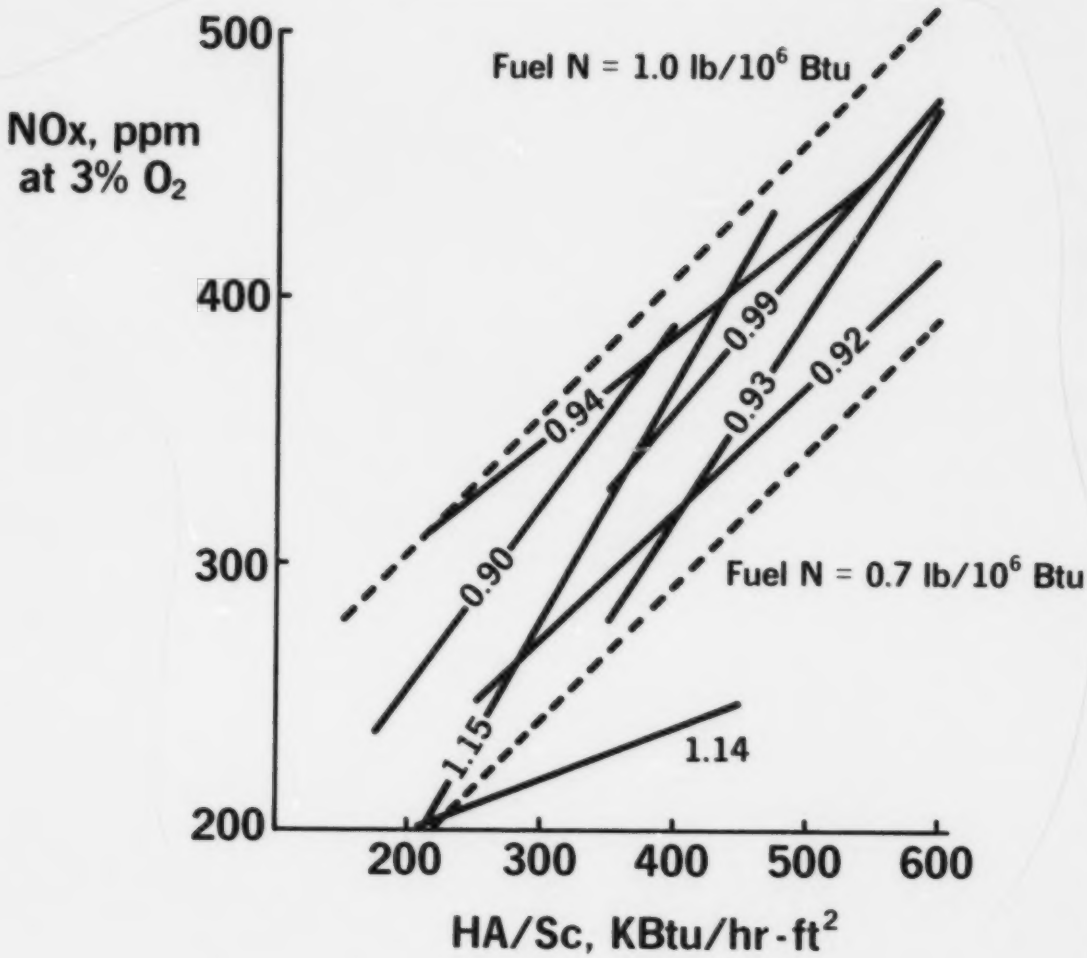
B&W low NO_x (coal) development

Figure 5



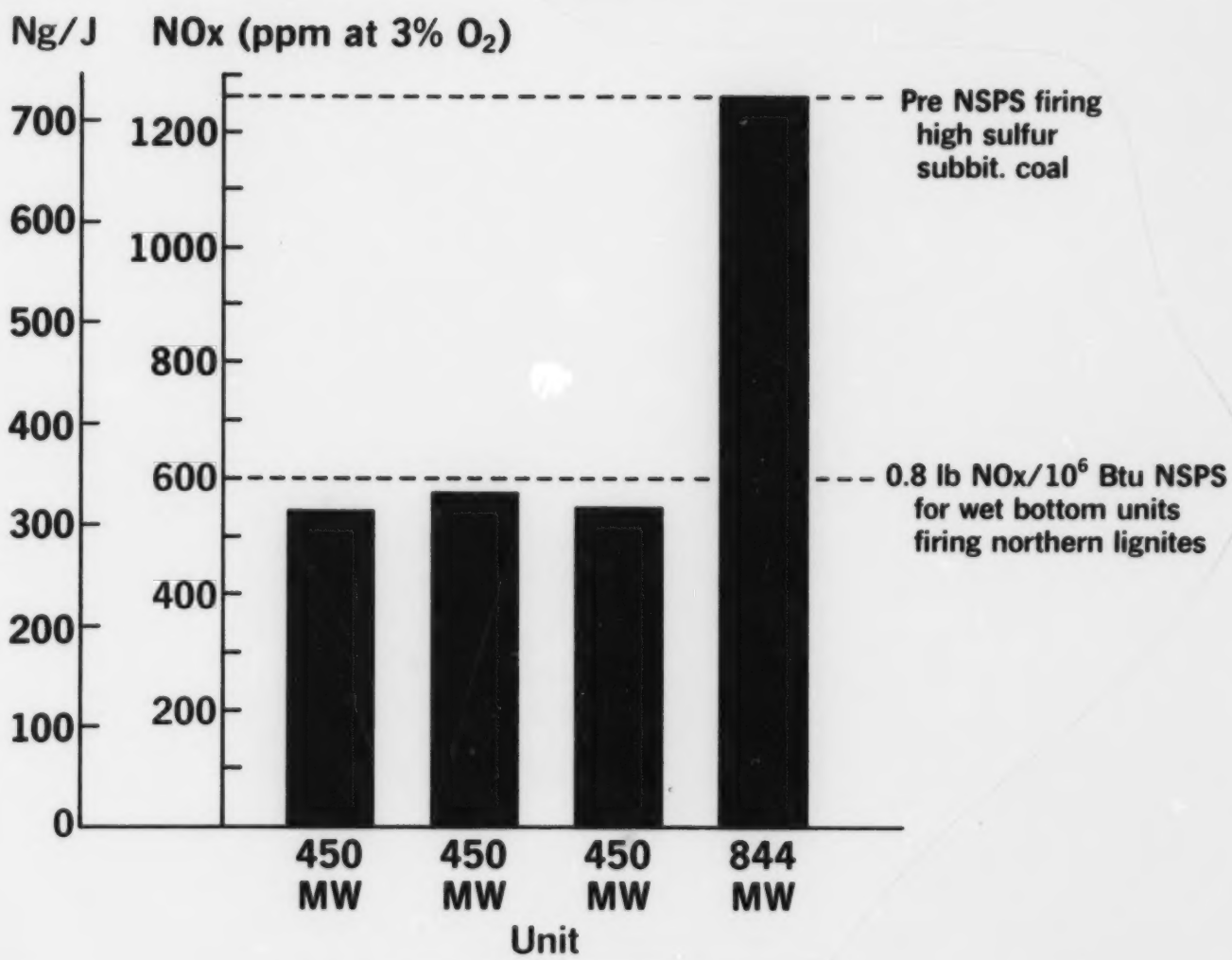
Low NO_x combustion system concept

Figure 6



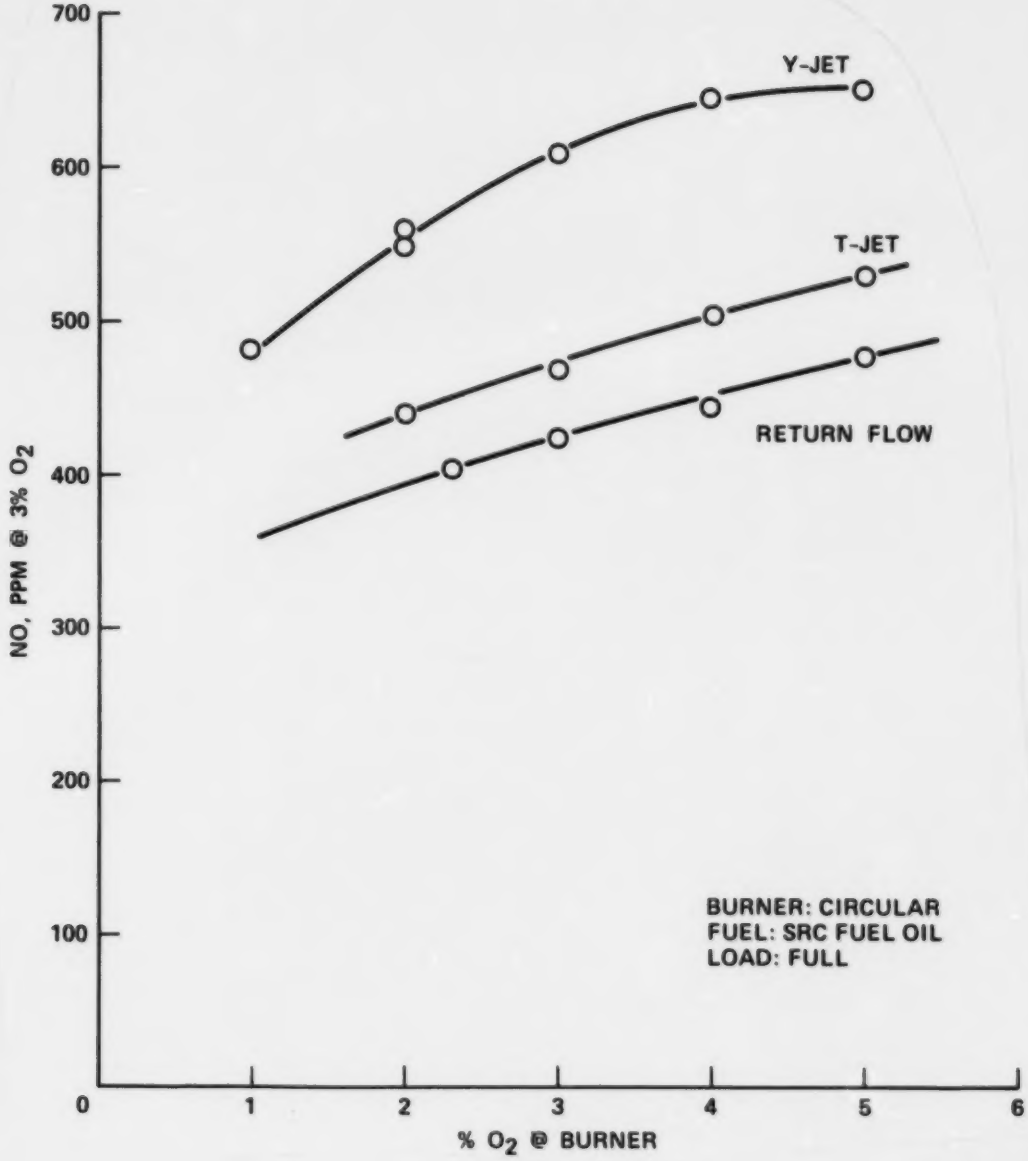
Fuel N_2 correlation with NO_X

Figure 7



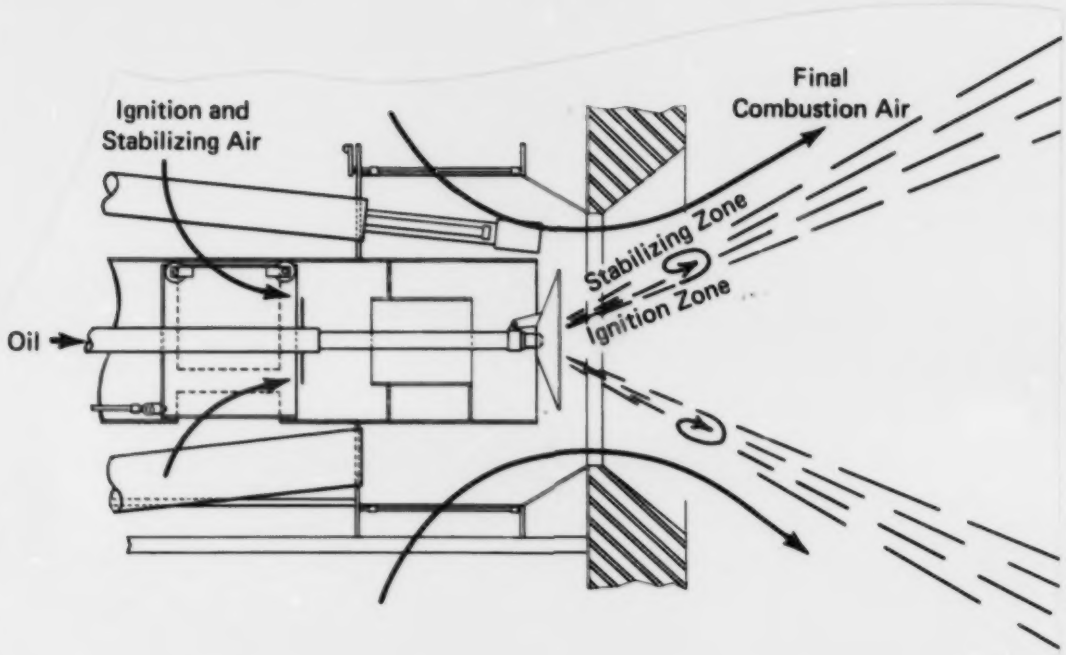
Cyclone furnace NO_X levels

Figure 8



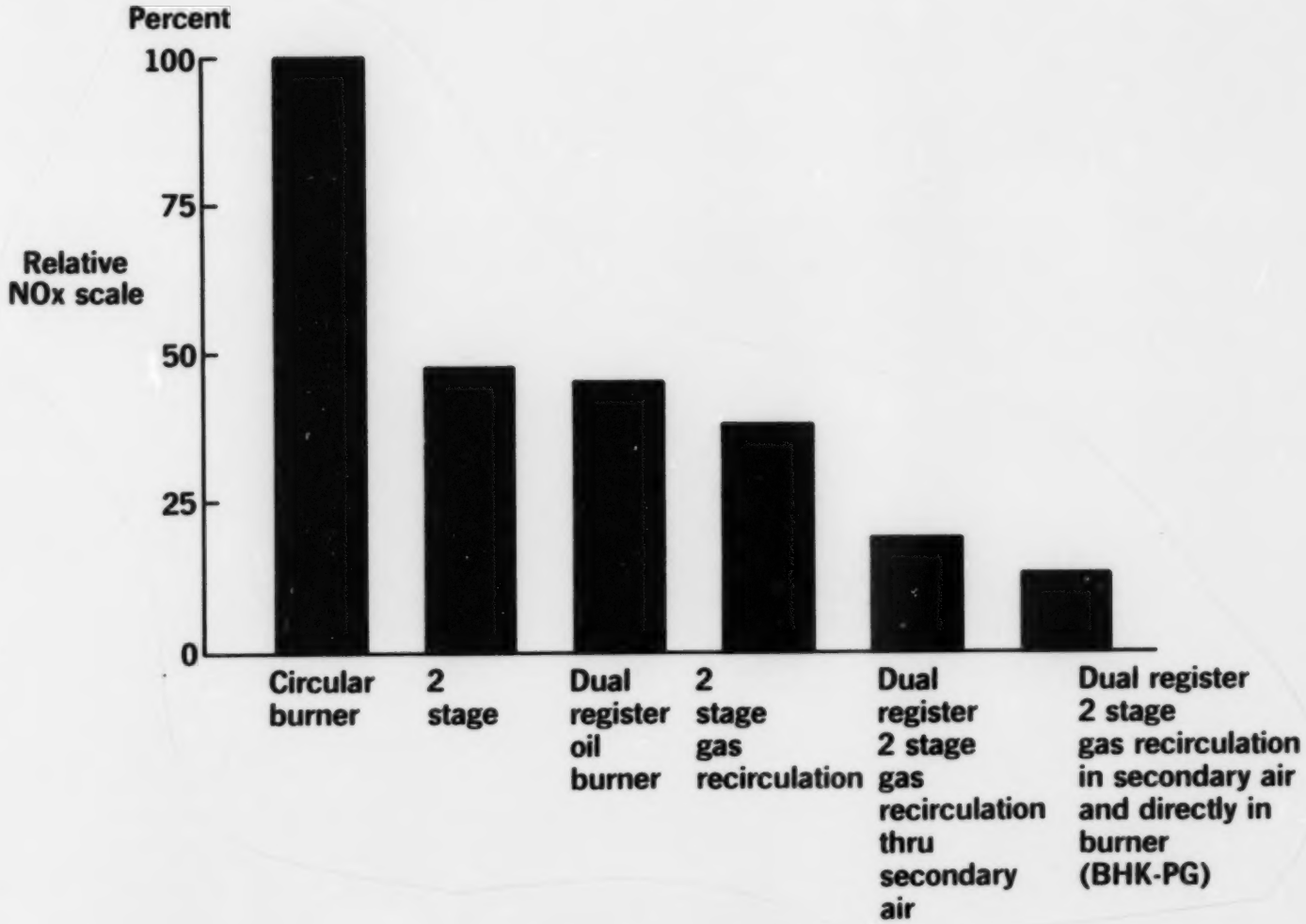
Influence of fuel atomizer design on NO_x emissions

Figure 9



Dual register oil burner

Figure 10



B&W low NOx (oil) development

Figure 11

CURRENT DEVELOPMENTS IN LOW NO_x FIRING SYSTEMS

By:

Tomozuchi Kawamura
Mitsubishi Heavy Industries, Ltd.
Tokyo, Japan

Donald J. Frey
Combustion Engineering, Inc.
Windsor, Connecticut, United States of America

ABSTRACT

Low NOx firing systems for natural gas and oil were developed for horizontal and tangential firing. The oil and natural gas "PM" firing system uses fuel rich and fuel lean regions in combination with flue gas recirculation to achieve low NOx emissions, the former region being produced by a diffusion flame, while the latter is produced by a premixed flame. The pulverized coal "SGR" and "LNCFS" tangential firing systems achieve low NOx emissions by delaying mixing of the main combustion air with the fuel.

INTRODUCTION

The reduction of NOx emissions from steam generators has become a paramount issue in most industrialized nations, with the strictest governmental regulations being in Japan and the USA (Table I). The local emission requirements in both countries are often more stringent than the national codes and vary considerably, depending in part on industrialization density and climatic conditions.

Although tangential firing has the lowest proven NOx emissions, Combustion Engineering, Inc. (C-E) and Mitsubishi Heavy Industries, Ltd. (MHI) have been deeply involved in NOx control studies for over a decade. Since the first oil embargo in 1973, C-E efforts have been directed primarily at controlling NOx formation in coal combustion and eventually led to the development of the "Low NOx Concentric Firing" (LNCF) concept. This system has been successfully demonstrated in both the laboratory (1) and the field (2) and is scheduled for rigorous testing in a large utility boiler, under contract with EPA (3). The results of these studies will be released following completion of additional testing in the utility units in mid-1981.

MHI first developed NOx control technology for oil and gas firing and the principles of this technology were proven with an impressive array of both new and retrofit applications. The continued price spiraling of fuel oil has altered the fuel market structure in Japan and the shift to coal as a fuel for steam generation has been increasing in recent years. Fortunately, the NOx control technology developed by MHI for gas and oil was found to be applicable to coal and the first commercial applications of these techniques are being evaluated currently.

C-E has obtained a license to apply the MHI NOx control techniques on steam generating equipment in the USA and Canada. The license covers two basic methods of reducing NOx emissions: control of NOx formation during combustion and removal of NOx from the flue gas following the completion of combustion. The latter system is described in a companion paper, "The Development of a Catalytic Reduction System for Coal-Fired Steam Generators" (4).

This paper will discuss the MHI method of controlling NOx generation during combustion and will describe the "PM" burner as originally developed for oil and gas, the "SGR" burner for coal, and finally, the PM burner for coal.

OIL AND GAS FIRING PM BURNER

PRINCIPLE OF OIL AND GAS FIRING PM BURNER

Recognizing that the "diffusion flame combustion system," employed in almost all existing oil-fired boilers, has a limitation on NOx production performance, MHI produced the PM burner, based on the "premix flame combustion theory" generally used in designing rockets. The marked reduction of NOx emission demonstrated by this burner has been recognized by both industry and academia and the operational results on actual boilers has been excellent.*

Here is the principle upon which this PM burner was developed. Generally speaking, there are two types of flames, diffusion flame and premixed flame (Fig. 1). The former is the flame that is produced when the injected fuel diffuses and burns while mixing with surrounding air. With this type of flame, NOx production decreases as air supply decreases and increases with increasing air. A premixed flame is one produced when the fuel is evenly mixed with air prior to ignition. With this type of flame, NOx production decreases with excessive air supply as well as with inadequate air supply. Combining the characteristics of premixing with "off-set" combustion, MHI developed the "off-set premixed flame theory." The PM burner is the product of a study based on this theory.

The concept of the PM burner is shown in Fig. 2. Combustion occurs in two different zones of the fuel-air mixture: in the fuel-rich mixture (NOx value at C_1) and in the fuel-lean mixture (NOx value at C_2) with the same total excess air ratio "X" as that for conventional burners. Thus, the average NOx value, point C (the mean value of C_1 and C_2) is markedly lower than that obtainable with conventional firing techniques. This is

*The 1977 prize of the Japan Society of Mechanical Engineers for excellent technical achievements was awarded to MHI because of this burner.

the case with gaseous fuels, i.e., they are burned under premixed conditions in both fuel-rich and fuel-lean mixtures, so the overall NOx value falls at point C.

With liquified fuels, however, burning occurs under diffused flame conditions in the fuel-rich mixture in order to maintain a stable flame. Thus, the overall NOx value is shown as Point C', the mean value of C_1' and C_2. The characteristically stable ignition associated with this PM burner provides the additional benefit of more flexible operation than conventional burners over a wide range of burner loads.

OIL-FIRED PM BURNER FOR TANGENTIAL FIRING

The corner assembly of a tangential firing system consists of a number of fuel nozzles stacked one upon another, the number depending on the total heat input to the unit. A typical fuel cell for the PM burner is shown in Fig. 3.

A specially designed atomizer produces two oil spray patterns; an inner conical spray for fuel-rich combustion and an outer "umbrella" partial spray for fuel-lean combustion. In order to control the oxygen atmosphere in the fuel-rich combustion zone, separate gas recirculation (SGR) is injected through nozzles on either side of the oil compartment. The outer (fuel-lean) oil is introduced through widely spaced atomizer ports, which permit passage of the SGR.

Thus, the inner spray ignites at the diffuser and burning occurs simultaneously with the mixing of fuel and air. The process is one of diffused combustion and corresponds to point C', in Fig. 2. Ignition of the outer spray is delayed and takes place after mixing with air from the auxiliary compartment. The process is one of premix combustion and corresponds to point C_2 in Fig. 2. The average NOx value is then at point C'.

Figure 4 shows the effects of NOx production of fuel nitrogen content, overfire air (OFA), flue gas premixed with total combustion air (GM), flue gas injection through SGR compartments (SGR), and total excess air. The effect of SGR on NOx production with various fuel oils is shown in Fig. 5.

OIL FIRED ROPM BURNER FOR HORIZONTAL FIRING

Figure 6 illustrates a typical structure of the oil fired ROPM burner assembly for horizontal-fired applications. The oil fired ROPM burner is composed of a fuel-rich oil spray, an air-rich oil spray, and intervening SGR.

Only one oil gun is provided at the center of the inside air passage. As was the case with the PM burner, the fuel oil is sprayed from the tip of the oil gun at two different spray angles forming two concentric hollow cones, providing an inner fuel-rich combustion zone and an outer fuel-lean zone. The NOx level vs. fuel N and NOx vs. SGR ratio of the oil fired ROPM burner are shown in Figs. 7 and 8.

GAS FIRED PM BURNER

Figure 9 illustrates a typical gas-fired cell of the PM burner assembly installed in a tangentially fired windbox. The cell consists of one fuel-rich nozzle and two air-rich nozzles.

The SGR nozzles are not installed since both the fuel-rich and fuel-lean nozzles produce premixed and almost straight flames and there is very little interference between these flames. If the boiler employs gas recirculation for furnace outlet gas temperature (FOT) control, the GR can be admitted between fuel cells, rather than through the furnace bottom, for more effective NOx control. The NOx level vs. GM ratio of the gas fired PM burner is shown in Fig. 10.

GAS FIRED ROPM BURNER

Figure 11 illustrates a typical structure of the gas fired ROPM burner assembly for horizontal firing, consisting of one fuel-rich gas burner and one fuel-lean burner. The air passage is radially divided into two sections; the fuel gas and air supplied through the central or internal passage produces the fuel-rich flame and the fuel gas and air supplied through the outside circular passage produces the fuel-lean flame.

An oil gun is shown in the center of the burner, but this is of a conventional design and is used only for auxiliary purposes, not for low NOx firing of oil. The NOx level vs. GM ratio of the gas fired ROPM burner is shown in Fig. 12.

COMMERCIAL APPLICATION OF OIL & GAS BURNERS

Recognizing the benefits and practical features of the PM burner, Tokyo Electric Power Company, Inc. (TEPCO) adapted the PM burner to its Anegasaki No. 5 unit (tangential gas-fired 600-MW unit) in 1977. The operation was excellent and the unit achieves very low NOx levels over the entire operating range of the boiler.

Table II is a list of operating converted boilers and several new contracts for both gas and oil fired PM burners.

As of this writing, a total of 25 boilers representing all kinds of firing—gas and oil, tangential and horizontal—have been put into commercial operation with PM burners. Selected data on four of these boilers is shown in Table III. The following facts were obtained from these installations:

(1) The theory of "Off-set Premix" has been proven in commercial installations and the operation of PM burners lends itself to industry practices.

(2) Low NOx emission levels are obtainable over a wide range of boiler loads.

(3) Combustion is extremely stable and the flames are easily detectable over the entire range of boiler loads.

Figure 13 shows the lowest NOx emission levels obtained in four actual boilers (same plants as for Table II). The chart compares PM burner performance with conventional burners.

COAL FIRED SGR BURNER FOR TANGENTIAL APPLICATIONS

STRUCTURES AND FUNCTION

Figure 14 shows a conventional coal tilting tangential firing cell, which consists of a coal compartment and two auxiliary air compartments. Coal and primary air are introduced through the center of the coal nozzle and some secondary air (termed "fuel air") passes through the annulus around the coal nozzle. The remainder of the secondary air (termed "auxiliary air") is introduced through separate compartments above and below the coal. Although the coal and air are admitted in

parallel streams, secondary air is continually introduced into the coal stream, both before and after ignition, and there is no clearly defined primary combustion zone.

The conventional burner has been redesigned to create separate primary and secondary combustion zones and has been named the "SGR burner" (Fig. 15).

The SGR burner has three features distinguishing it from the conventional burner:

1) Gas recirculation is introduced through SGR compartments above and below the coal nozzle.
2) The auxiliary air compartments are farther from the coal compartment.
3) The coal nozzle has a divergent tip, which acts as a flame holder for maintaining ignition close to the nozzle.

The first two features maintain a reducing atmosphere at the nozzle during primary combustion by minimizing the infusion of secondary air into the coal stream. The third feature assures that devolatization and improved combustion of the coal occurs within this fuel-rich primary combustion zone.

TEST RESULTS WITH SGR BURNER

MHI has two coal-fired test furnaces at its Nagasaki research laboratory. The smaller furnace is water cooled, of circular wall, steel construction with refractory lining and rated at 0.5 TPH. The larger furnace is similar in construction and rated at 4 TPH.

Two SGR test burners were constructed and tested; the first with a capacity of 525 kg/h was tested in the small furnace and the other, rated at 3000 kg/h, was tested in the larger furnace. Both were of a design similar to that shown in Fig. 15.

The test results are shown in Figs. 16 through 21. Analysis of coals indicated in these figures is shown in Table IV.

(1) Effect of excess air on NOx is shown in Figs. 16 and 17. As with conventional burners, decreasing excess air is an effective method of reducing NOx.
(2) Effect of OFA on NOx is shown in Figs. 18 and 19. Again, its effect is characteristic of most other burner designs.

(3) Combined effect of OFA and SGR on NOx is shown in Figs. 20 and 21. The concept of the SGR ports was to impede the ingress of secondary auxiliary air into the primary combustion zone in which devolatilization and combustion occurs. These tests indicate that the effectiveness of SGR varies from coal to coal. In those cases where it is ineffective, minimum SGR flow is introduced for cooling these ports without introducing air, which would increase NOx.

CONFIRMATION OF BURNER SCALE-UP PERFORMANCE

MHI has had considerable experience relating test furnace performance to actual field performance with converted burners. This experience indicates that if the following relationship is maintained between the burner firing rate (Q) and the burner height (H), the NOx emissions from the burners will be the same:

$$H=AQ^N \text{ where A is a constant}$$

Figure 22 shows the results of such an investigation and compares the NOx production of a small burner in this test facility with a full sized burner in the Takasago No. 1 unit, firing the same coal. The burner design for both coals was conventional tangential type.

COMMERCIAL APPLICATION OF COAL-FIRED SGR BURNER

The first commercial application of the SGR burner is Matsushima 1 and 2 of Electric Power Development Co. (EPDC). These are duplicate 500-MW boilers and the first large coal-fired units ordered after a decade of oil and gas utilization.

Since Matsushima 1 has just started its trial operation, we do not yet have data on the performance of its SGR burners. We plan to have this information within a few months.

Figure 23 shows the relationship between burner capacity (Q) and burner height (H) for the same NOx production. This is based on the formula discussed previously and shows control data points taken from the test furnaces and the Takasago unit. From this relationship, it is expected that the 1830 mm burner height for Matsushima will achieve the same NOx emissions as demonstrated for that coal in both small and large test furnaces.

An analysis of the coals tested in the two test furnaces thus far are shown in Table IV.

COAL FIRED PM BURNER

During the study of the SGR coal burner, which is the first design series in the low NOx coal burner program, MHI collected data pertaining to the relation between the primary air/coal ratio and NOx formation for the purpose of determining possible further improvements in low NOx burners.

Data from the test furnaces is plotted in Fig. 24 and one can see that when the primary air/coal ratio is in the range from 1-3, the NOx value decreases as this ratio is reduced with every kind of coal tested, although the slopes of the curves vary.

On the other hand, C-E had acquired data on the relationship between the primary air/coal ratio and NOx formation at ratios ranging from 3 to 8, which is higher than the usual ratios. Some of this data is shown in Fig. 25, including that of a Japanese coal and an Australian coal which had been sent to C-E for testing.

Figure 25 presents a quite different trend from that of Fig. 24, in that the NOx value decreases as the primary air increases when the primary air/coal ratio ranges between 2 and 7 or 8. The test results in these two cases are apparently contradictory, but may be explained as follows.

By means of the explanation of the principle of the PM burner, the principle of the SGR burner will become clear as well.

PRINCIPLE OF NOx REDUCTION

Generally, the pulverized coal combustion zone is theoretically divided into two sub-zones as shown in Fig. 26; one is the primary combustion zone where pulverized coal carried by primary air burns while mixing with that primary air, and the other is the secondary combustion zone where the remainder of the coal burns while mixing diffusing secondary air injected from the auxiliary air compartments. However, with conventional burners the secondary air starts to mix with the primary air/coal stream as soon as they are injected into the durnace and distinct primary and secondary combustion zones do not exist.

Thus, volatile matter burns with high excess air instead of burning only with the primary air in the primary combustion zone.

Because of this, the combustion process and NOx reducing theory described here can not be applied to conventional burners. In other words, MHI's Low NOx burners are so designed that they can establish distinctly separate primary and secondary combustion zones.

The quantity of coal that burns in the primary combustion zone is proportional to the ratio of primary air to coal and the quantity of coal that burns in the secondary combustion zone is the remainder of the coal. Thus, the amount of NOx generated from the combustion of pulverized coal can be expressed as a sum of that generated in the primary and that in the secondary combustion zones, as shown in Fig. 27.

(1) The formation of NOx in the primary combustion zone ({NOx}p) in Fig. 27.

The primary air/coal ratio of 3-4 approximately corresponds to the air quantity theoretically required for combustion of volatile matter in coal. In the region where this ratio is within the range of 3-4, primary air is almost all consumed by the combustion of volatile matter. At lower ratios, oxygen availability is decreased, the combustion of volatile matter is retarded, and the conversion of N in volatile matter to NOx is reduced. Moreover, as a result of incomplete combustion, the quantity of unburned gas from the volatile matter entering the secondary combustion zone is increase.

A primary air/coal ratio of 7-8 corresponds to the air quantity theoretically required for complete combustion of the coal. Therefore, in the region where the primary air/coal ratio is between 3-4 and 7-8, O_2 is insufficient for the complete combustion of fixed carbon but the conversion of N in volatile matter to NOx becomes more active as the ratio increases. However, the reducing action on NOx formation of substances such as HC, NH_3, HCN etc., produced from the fixed carbon, also becomes more active, with the net result that the NOx valued at the outlet of the primary combustion zone eventually drops as the primary air/coal ratio increases.

Primary air/coal rations greater than 7-8 result in excess air combustion, negating the NOx reducing action and resulting in a steep rise of NOx value.

Thus, the NOx formed in the primary combustion zone has the characteristics as expressed by the solid lines in the chart of $(NOx)_p$ in Fig. 27.

(2) The formation of NOx in the secondary combustion zone ({NOx}s in Fig. 27):

In the region where the primary air/coal ratio is less than 3-4, a large quantity of unburned gas from the primary combustion zone burns with the char as the secondary air diffuses and mixes with them in the secondary combustion zone. The quantity of unburned gas increases as the primary air/coal ratio is throttled further, and causes relative retardation of diffusion and mixing of secondary air and a consequent drop of the conversion rate of N in unburned gas and char to NOx. Thus, the formation of NOx varies little with the change of the primary air/coal ratio, as shown by the heavy solid line in the chart.

In the region where the primary air/coal ratio is between 3-4 and 7-8, the percent of coal that burns in the primary combustion zone increases as the primary air/coal ratio increases. Consequently, the percent of the coal that burns in the secondary combustion zone decreases and the formation of NOx in this zone decreases.

The sum of (NOx)p from the primary combustion zone and (NOx)s from the secondary combustion zone is the total of the NOx produced from the combustion of pulverized coal. As shown in the bottom chart in Fig. 27, NOx increases in the region where the primary air/coal ratio is between 0 and 3-4 and decreases in the region where that ratio is between 3-4 and 7-8 and increases again when that ratio exceeds 7-8.

PRINCIPLE OF THE COAL FIRED PM BURNER

It is a tested conclusion that with coal fired burners, the NOx value is high in the region where the primary air/coal ratio is 3-4 and falls as the ratio deviates in either direction, increasing or decreasing. This is a similar trend in NOx formation to that which occurs with the premixed oil and gas fired burners when the air ratio

is approximately 1 and falls as the ratio deviates from this point in either direction.

In a direct-fired system, the pulverizer is directly coupled with the firing system. The primary air/coal ratio is dictated by pulverized drying and conveying requirements, and generally falls in the range 1.5-2.0. Pulverizers provided with spare capacity, can increase this ratio to 3.0 or thereabout. This is undesirable in a normal firing system since NOx increases as this ratio increases, as shown in Fig. 27. Fortunately the relation between the NOx value and the primary air/coal ratio in combustion of coal is similar to that between the NOx value and the air ratio in premixed combustion of oil and gas. This suggests the possibility of using the principle of fuel-rich and fuel-lean with coal, as well, and this forms the basic principle of the PM burner.

Referring again to the bottom chart in Fig. 27, the circled points illustrate the low NOx burner. The coal-air mixutre from the pulverizer can be divided into two streams; one with a ratio of C_1 (fuel-rich) and the other C_2 (fuel-lean). If these two streams are permitted to fire independently, the NOx emission level for the whole burner assembly will be the level corresponding to the point C_0 which is considerably lower than the point C'_0 which represents the NOx emission level obtainable if the entire coal/air stream burned as a single flame in separate primary and secondary combustion zones, as with the SGR burner. The structure of the coal fired PM burner is shown in Fig. 28. The concentrating effect of coal to the outside radius of the delivery pipe is used to make the separation between concentrated and dilute coal streams. Figure 29 shows comparison of NOx emission of conventional burner, SGR burner and PM burner.

CONCLUSION

The PM burner for oil and gas, based on "Offset Premix Flame Theory," successfully achieves dramatically lower NOx emission levels than is possible with conventional burners. The most prominent feature of the oil and gas PM burner is that it can greatly reduce NOx emission while maintaining stable combustion. Moreover, it can reduce

particulate matter emission as well and requires no additional effort in operation and maintenance of the equipment. Neither catalyst nor ammonia injection is needed. Thus, the advantages of the PM burner may be summarized by stating that it can effect a marked reduction in NOx emission economically, not only in new boiler applications but in most retrofit applications, as well.

A number of oil and gas PM burners have already been successfully applied to various types of boilers such as supercritical pressure, forced and natural circulation, pressurized, and balanced draft, indoor and outdoor types. The fact that all these burners have been operated successfully and to the customer's satisfaction is proof that this burner design is applicable to any type of utility boiler.

In the case of coal-firing, the SGR burner provides an effective means of reducing NOx, but field confirmation of its performance must await testing to the Matsushima until later this year.

We believe that the more recently tested coal-fired PM burner will replace the SGR burner on future new boiler applications since its potential for NOx reduction is much superior. The current status of the low NOx burners, then, is shown in Fig. 30.

REFERENCES

1. EPA Contract No. 68-02-1885

2. C-E Studies at Richmond Power & Light Company, Whitewater Unit No. 2

3. EPA Contract No. 68-02-3655.

4. Sengoku, T., Todo, Y., Yokoyama, N., and Howell, B. M., "The Development of A Catalytic NOx Reduction System for Coal-Fired Steam Generators,"Presented at the EPRI-EPA Joint Symposium on Stationary Combustion NOx Control, Denver, Colorado, October 6-9, 1980; Published as Combustion Engineering publication TIS-6710, Windsor, CT: Combustion Engineering, Inc., 1980

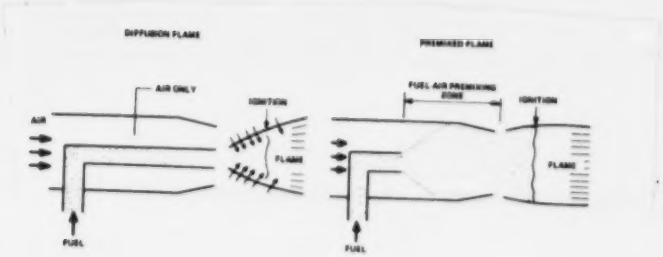


Fig. 1: Diffusion flame and premixed flame

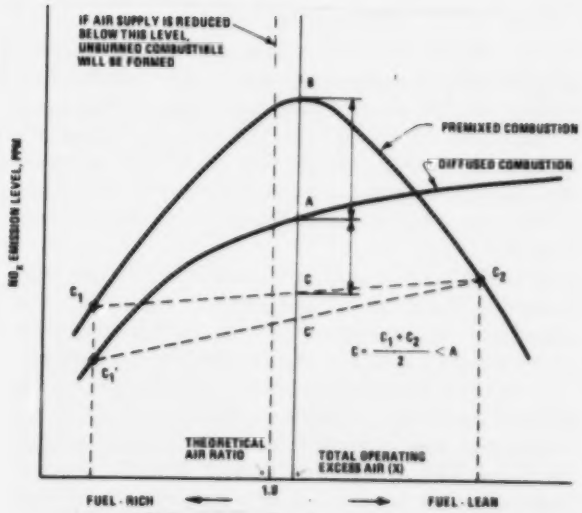


Fig. 2: Concept of the PM burner

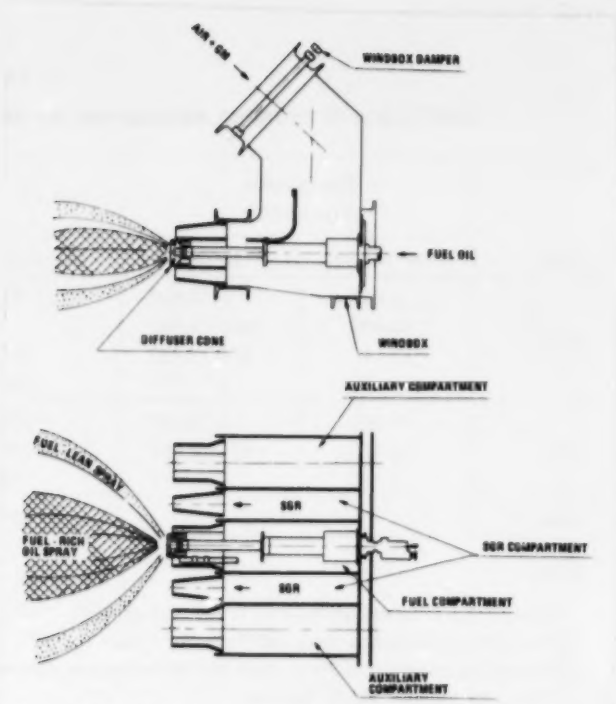


Fig. 3: PM burner cell for firing oil in tangential firing system

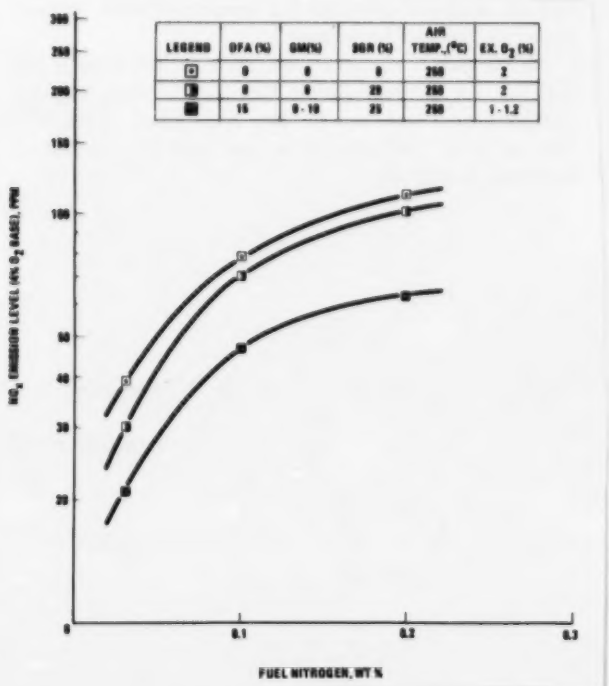


Fig. 4: Oil fired PM burner for tangential firing—fuel N vs. NOx emission

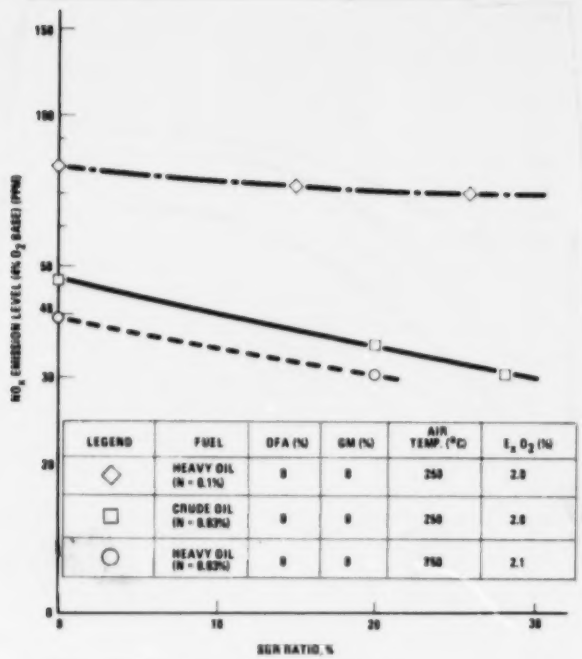


Fig. 5: Oil fired PM burner for tangential firing—SGR ratio vs. NOx emission (test furnace)

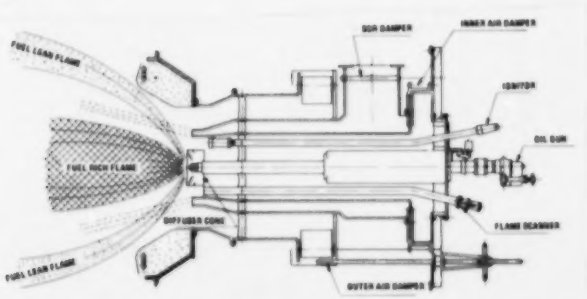


Fig. 6: Structure of oil fired ROPM burner for horizontal firing

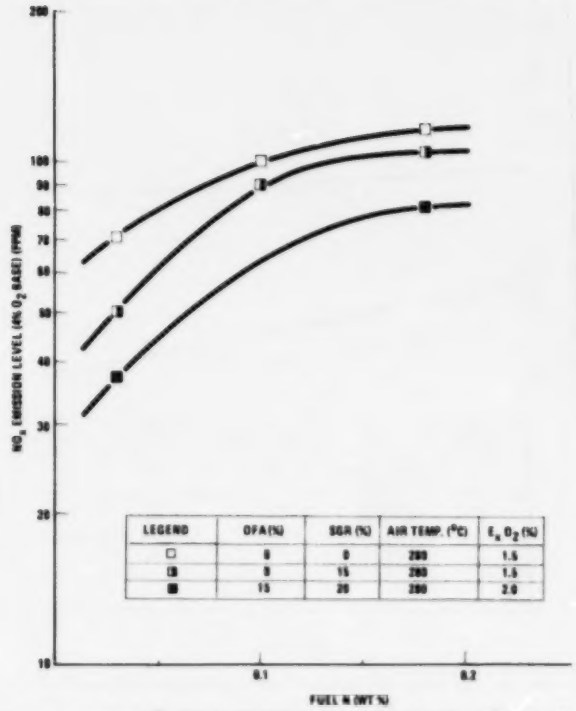


Fig. 7: Oil fired ROPM burner for horizontal firing—fuel N vs. NOx emission (test furnace)

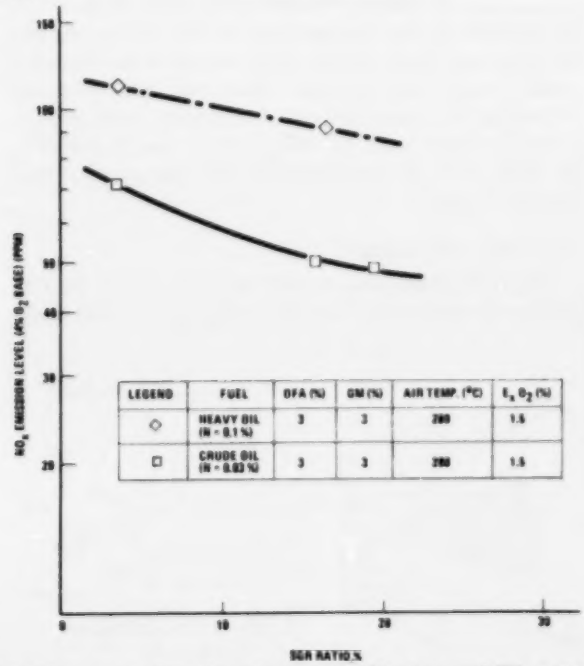


Fig. 8: Oil fired ROPM burner for horizontal firing—SGR ratio vs. NOx emission (test furnace)

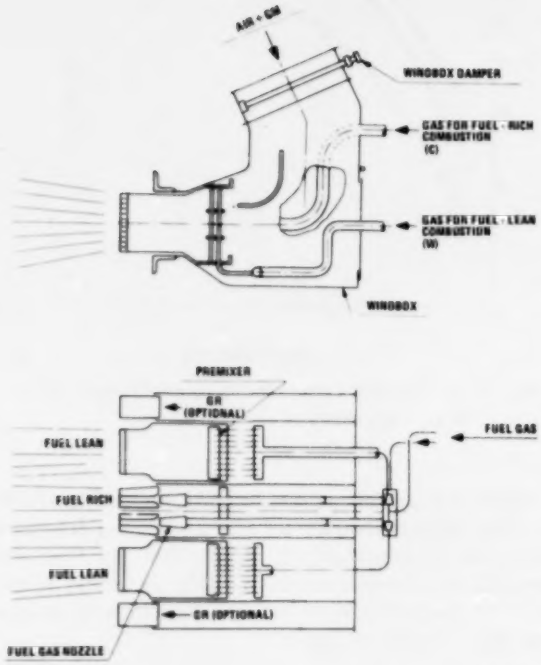


Fig. 9: PM burner cell for firing gas in tangential firing system

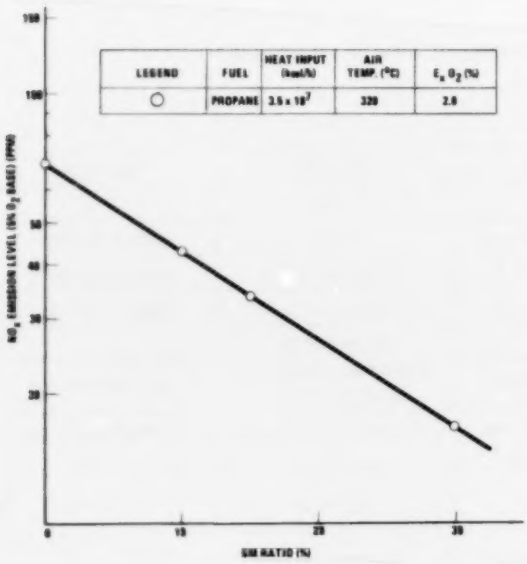


Fig. 10: Gas fired PM burner for tangential firing—GM ratio vs. NOx emission (test furnace)

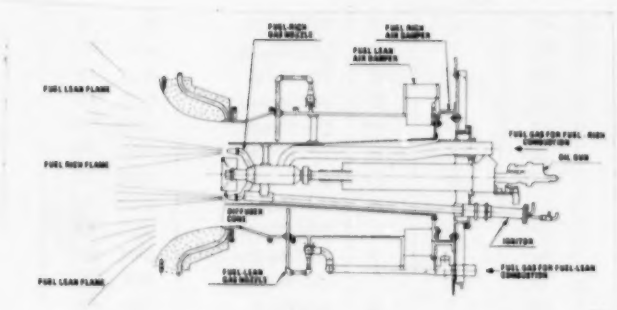


Fig. 11: Structure of gas fired ROPM burner for horizontal firing

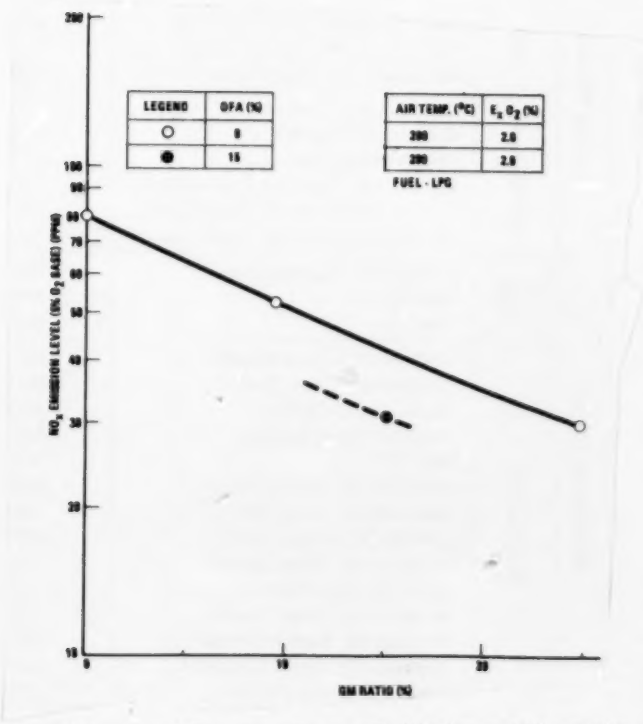


Fig. 12: Gas fired ROPM burner for horizontal firing—GM ratio vs. NOx emission

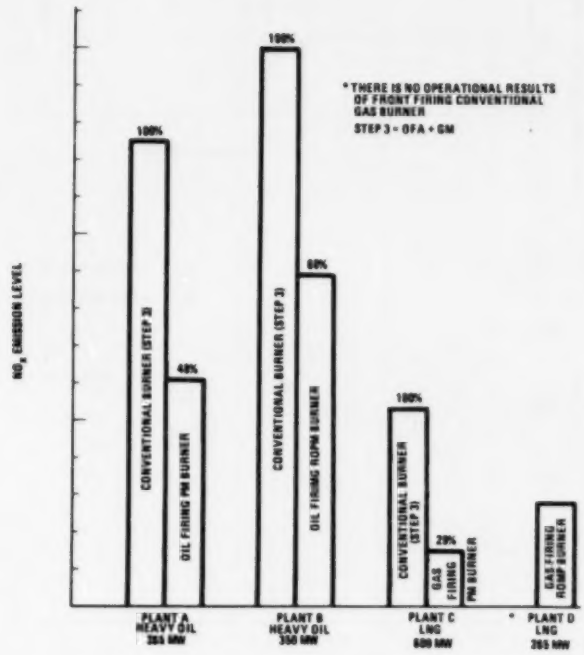


Fig. 13: Operational results of PM burner in actual boiler (comparison of minimum NOx before and after modification)

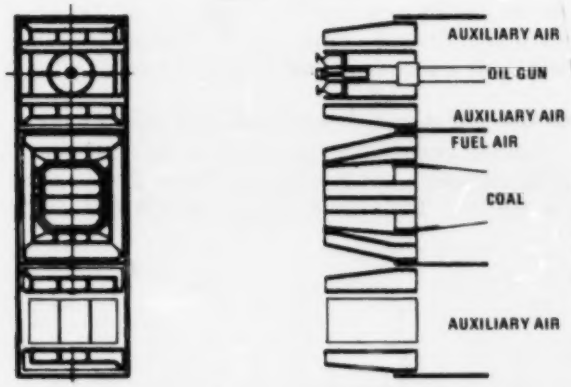


Fig. 14: Configuration of conventional coal tangential firing nozzle

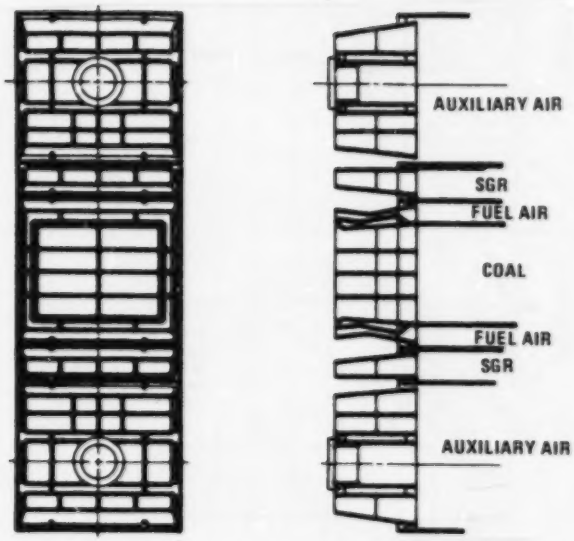


Fig. 15: Configuration of SGR burner for coal tangential firing nozzle

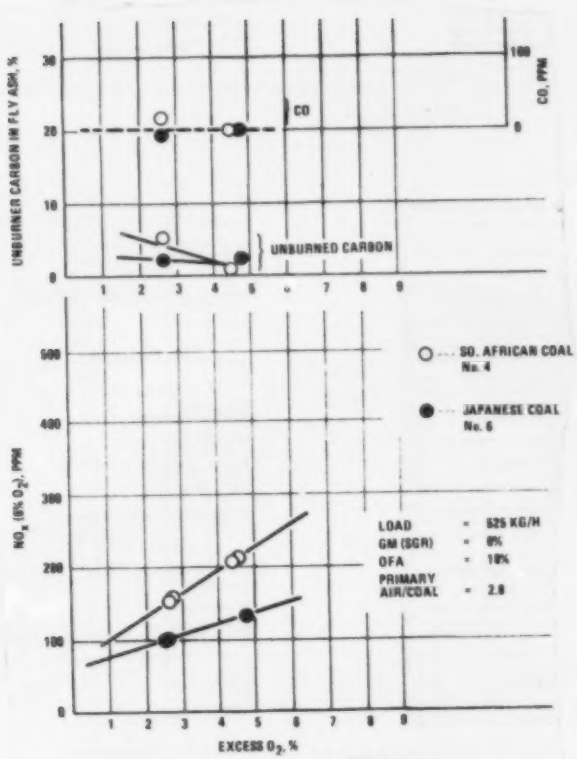


Fig. 16: NOx with excess O_2 SGR test burner

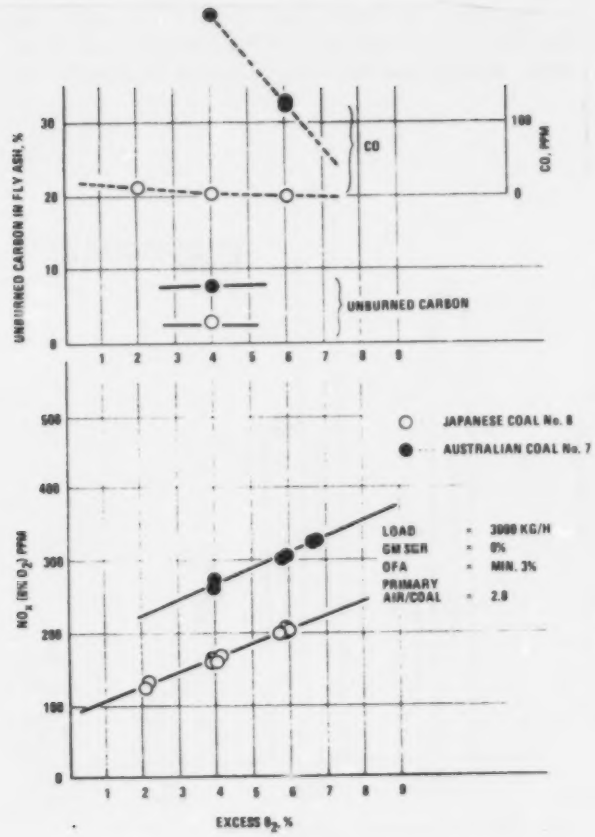


Fig. 17: NOx reduction with excess O^2—SGR: 3000 kg/h capacity test burner

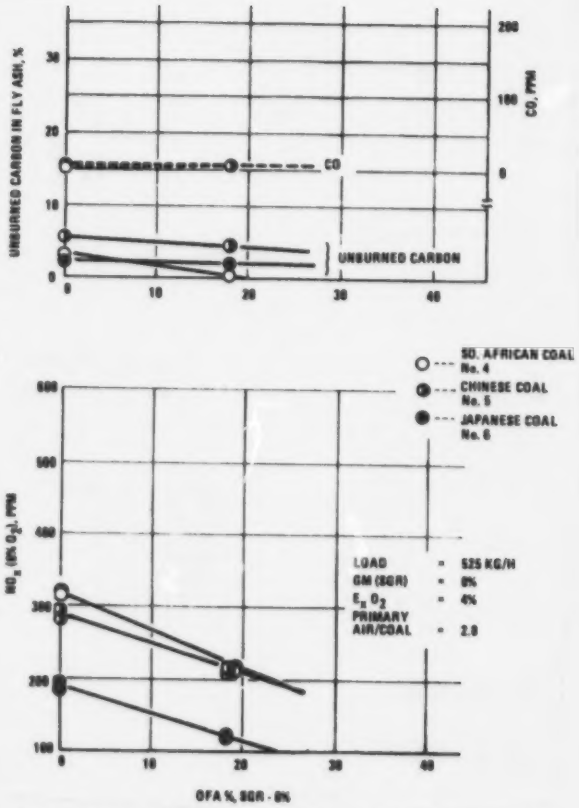


Fig. 18: NOx reduction with OFA—SGR

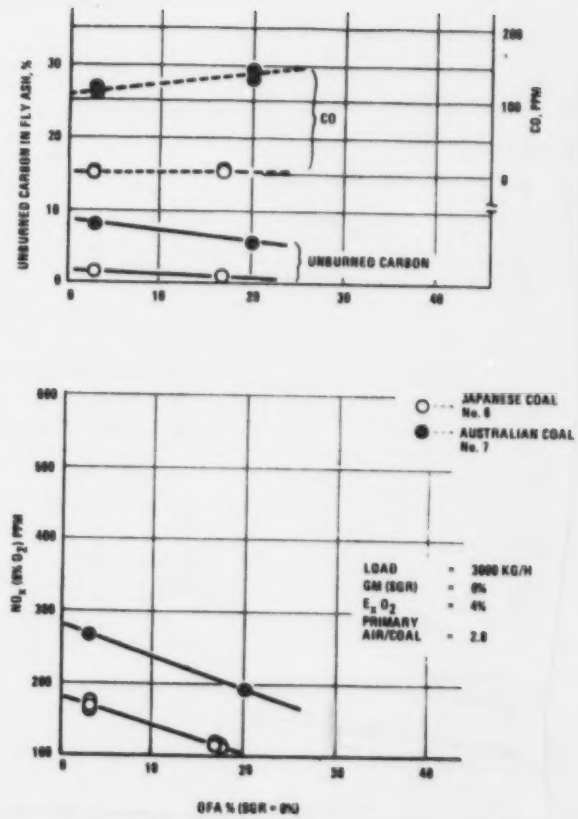


Fig. 19: NOx reduction with OFA—SGR

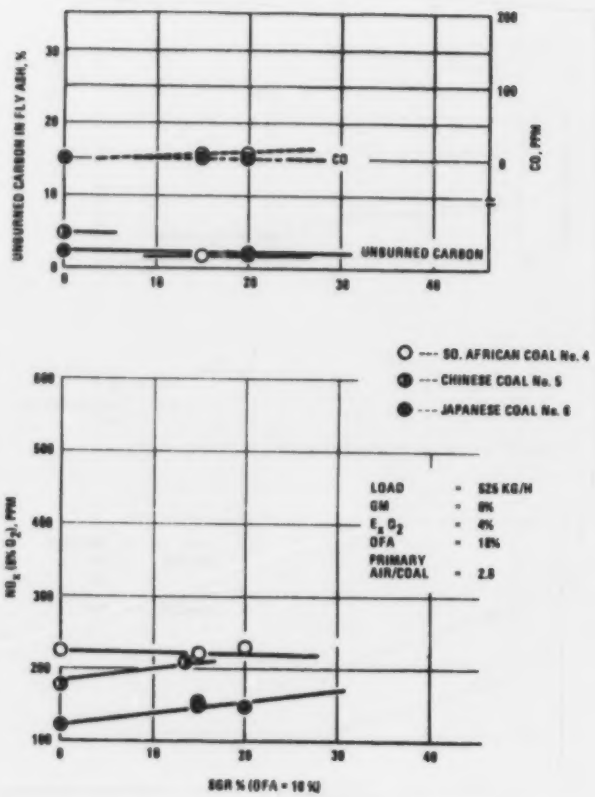


Fig. 20: NOx reduction with SGR of OFA=18%—SGR

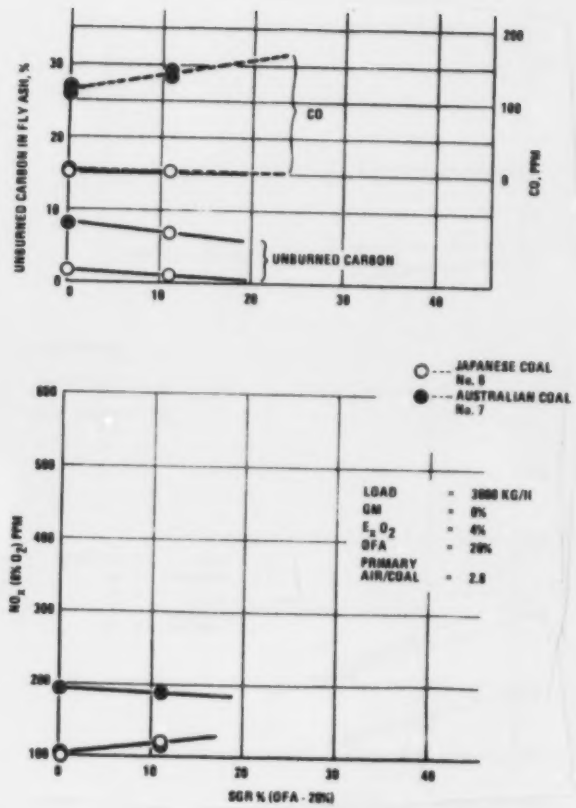


Fig. 21: NOx reduction with SGR at OFA=20%—SGR

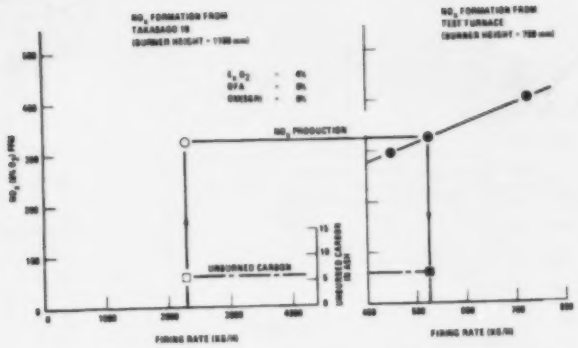


Fig. 22: Relationship between burner size and burner capacity for the same NOx formation (conventional and tangential burner

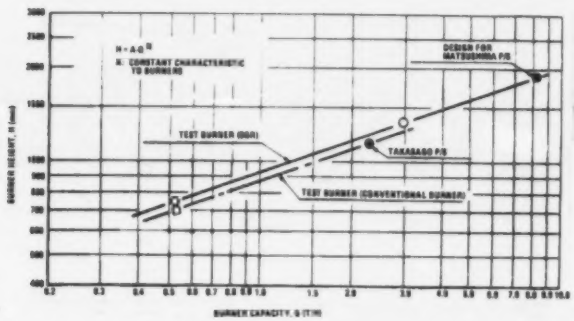


Fig. 23: Relation between burner size and burner capacity for the same NOx formation (conventional burner)

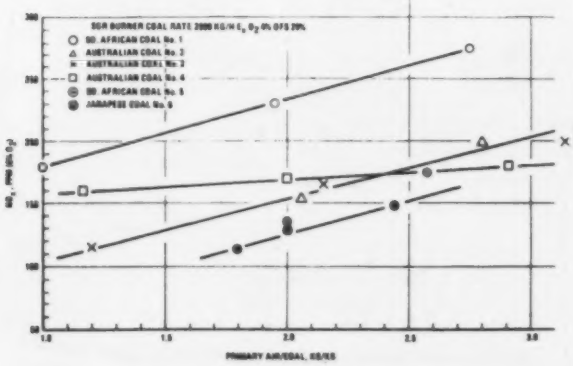


Fig. 24: NOx primary air-coal (fuel rich side)

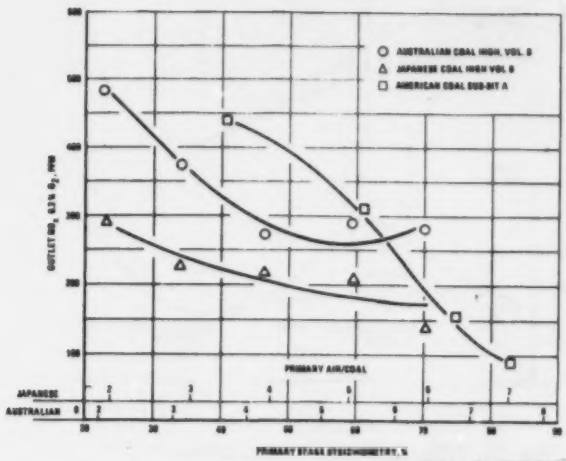


Fig. 25: Effect of primary stage stoichiometry on NOx (fuel lean side C-E)

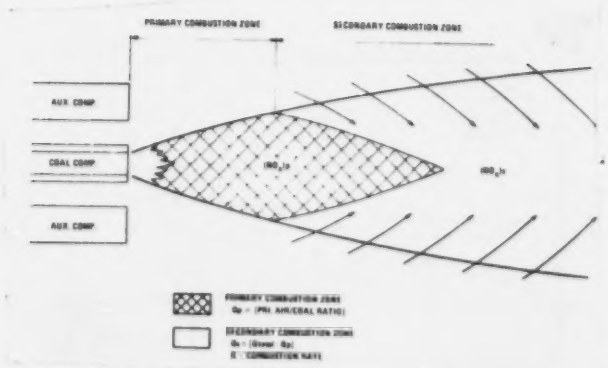


Fig. 26: Combustion model of pulverized coal firing

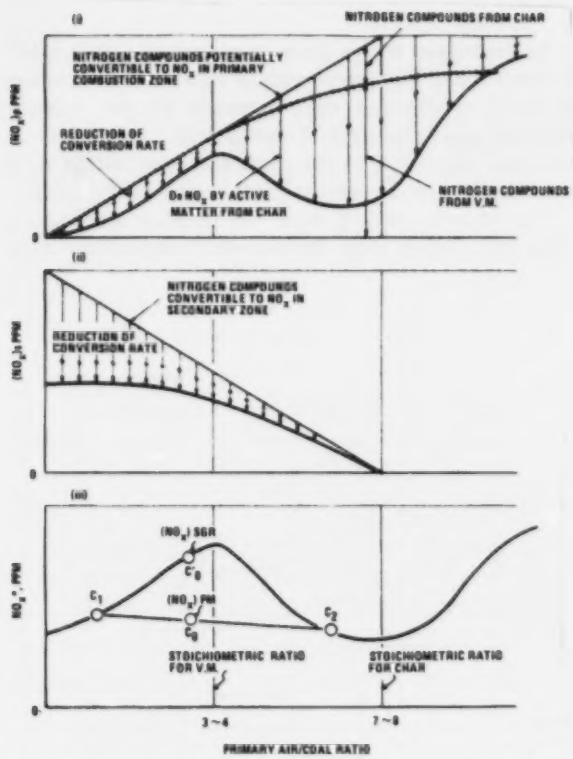


Fig. 27: NOx formation characteristics with primary air/coal ratio and conceptional figure of PM coal burner

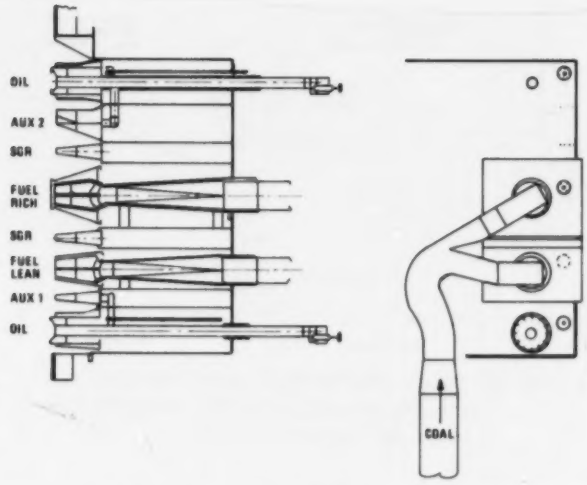


Fig. 28: Structure of coal-fired PM cell in tangential firing system

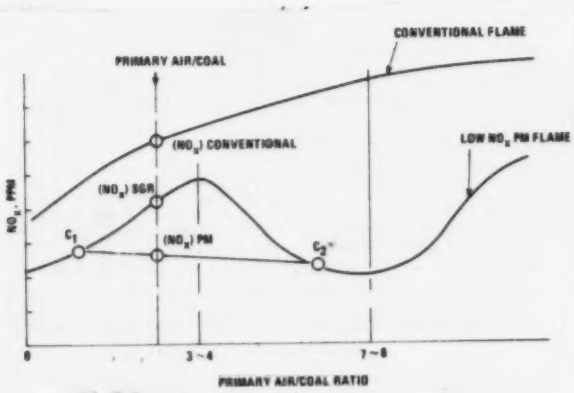
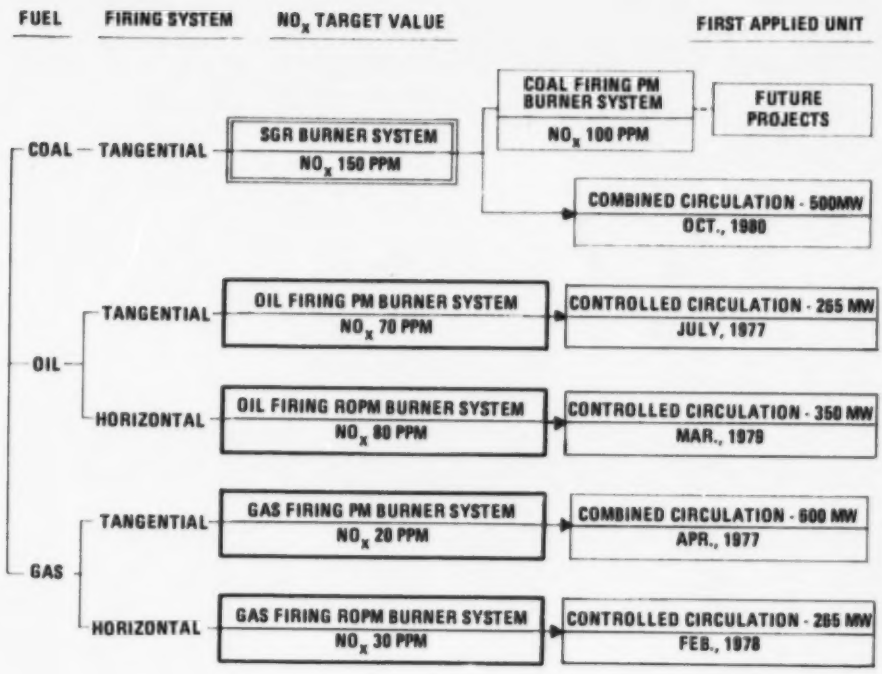


Fig. 29: Comparative NOx formation characteristics of coal-fired PM and conventional flames



NOTE: (1) ALREADY IN COMMERCIAL OPERATION

NOW UNDER CONSTRUCTION OF MANUFACTURING

(2) KIND OF FUEL COAL: AVERAGE JAPANESE BITUMINOUS COAL
OIL: HEAVY OIL (N 0.1%)
GAS: NATURAL GAS

(3) NO_x PPM BASIS: 4% O_2 FOR OIL, 5% O_2 FOR GAS, 6% O_2 FOR COAL (DRY VOL)

Fig. 30: Development of PM burner system by MHI

TABLE I

COMPARISON OF NATIONAL REGULATIONS ON NO_X EMISSION RATES IN JAPAN AND UNITED STATES

Fuel	Gas Quantity Rate Emitted		Allowable NO_X Emission Rates for New Units			
			Japan (1977)		USA (1979)	
	① 10^3 Nm^3/h	② 10^3 SCF/h	③ ppm at 3% O_2	lb/10^6 Btu	ppm at 3% O_2	lb/10^6 Btu
Gas	≥500	≥ 18,662	68	0.08	161	0.2
	40-500	1493-18,662	113	0.14		
	10- 40	373- 1493	146	0.18		
	≤ 10	≤ 373	169	0.21		
Oil	≥ 500	≥18,662	138	0.18	230	0.3
	10-500	373-18,662	159	0.21		
	≤ 10	≤ 373	191	0.25		
Coal	No stipulation		480	0.67	④360/⑤432	④0.5/⑤0.6

Notes:

①Normal cubic meters per hour (0°C and 760 mm Hg).

②Standard cubic feet per hour (60°F and 14.7 psia).

③Values are corrected to 3% O_2 base for convenience in comparing with USA standards. Japanese values based on 4% O_2 for oil, 5% O_2 for gas, and 6% O_2 for coal.

④Sub-bituminous coal and solids derived from coal.

⑤Most other coals.

TABLE II

LIST OF UTILITY BOILERS EQUIPPED WITH MHI PM BURNER SYSTEM

		Unit name	Unit cap. (MW)	Boiler type	Firing	Draft	Fuel/Atomization	Start of operation
Gas firing PM burner	New Unit	Anegasaki #5, Tokyo Electric	600	SC	T	P	LNG, LPG/-	APR., '77
		Tobata Kyodo #4, Tobata Joint Elec.	375	CC	T	B	LNG, BFG/-	FEB., '78
		Shin-Kokura #3, Kyushu Electric	600	SC	T	P	LNG/-	SEP., '78
		Shin-Kokura #4, Kyushu Electric	600	SC	T	P	LNG/-	JUN., '79
		Sodegaura #4, Tokyo Electric	1000	SC	T	P	LNG/-	JUN., '79
	Modified unit	Goi #3, Tokyo Electric	265	CC	H	P	LNG, Oil/Steam	MAR., '78
		Goi #1 Tokyo Electric	265	CC	H	P	LNG, Oil/Steam	FEG., '79
		Goi #5, Tokyo Electric	350	C	H	P	LNG, Oil/Steam	APR., '79
		Minami-Yokohama #3, Tokyo Electric	450	CC	T	P	LNG/-	JULY, '79
		Minami-Yokohama #2, Tokyo Electric	350	CC	T	P	LNG/-	NOV., '79
		Minami-Yokohama #1, Tokyo Electric	350	CC	T	P	LNG/-	MAR., '80
Oil Firing PM burner	New unit	Iwakuni #3, Chugoku Electric	600	SC	T	P	LPG, Oil/Steam	JULY., '81
		Plant "S"	350	SC	T	P	Oil/Steam	SEP., '82
		Plant "J"	600	SC	T	B	Coal, Oil/Steam	NOV., '82
	Modified unit	Yokosuka #1, Tokyo Electric	265	CC	T	B	Oil/Mech.	JULY, '77
		Kashima #1, Tokyo Electric	600	SC	T	P	Oil/Mech.	MAY, '78
		Ooi #1, Tokyo Electric	350	CC	T	P	Oil/Mech.	JULY, '78
		Chiba #1, Tokyo Electric	125	NC	T	B	Oil/Steam	MAY, '78
		Plant "H"	350	CC	T	P	Oil/Mech.	NOV., '78
		Yokosuka #2, Tokyo Electric	265	CC	T	B	Oil/Steam	DEC., '78
		Yokosuka #4, Tokyo Electric	350	CC	H	P	Oil/Steam	MAR., '79
		Kashima #3, Tokyo Electric	600	SC	T	P	Oil/Mech.	MAR., '79
		Yokosuka #5, Tokyo Electric	350	CC	H	P	Oil/Steam	JUN., '79
		Chiba #2, Tokyo Electric	125	N/C	T	B	Oil/Steam	JUN., '79
		Yokosuka #3, Tokyo Electric	350	CC	H	P	Oil/Steam	DEC., '79
		Takasago #2, Kansai Electric	450	SC	T	P	Oil/Mech.	JAN., '80
		Takasago #1, Kansai Electric	450	SC	T	P	Oil/Mech.	APR., '80
		Sanpo #1, Kansai Electric	156	CC	T	B	Oil/Mech.	JUN., '80

Note: Boiler type: NC—Natural circulation, CC—Controlled circulation, SC—Combined circulation
Firing: T—Tangential, H—Horizontal Draft: P—Pressurized, B—Balanced

TABLE III
PRINCIPAL DATA OF BOILERS EQUIPPED WITH VARIOUS TYPE OF PM BURNERS

Item \ Unit	A	B	C	D
Burner type	Oil-PM	Oil-ROPM	Gas-PM	Gas-ROPM
Unit output (MW)	265	350	600	265
Fuel	Heavy oil	Heavy & crude oil	LNG	LNG & Naphtha
Firing system	Tangential firing	Horizontal firing	Tangential firing	Horizontal firing
Draft system	Balanced draft	Pressurized draft	Pressurized draft	Pressurized draft
Type of boiler	Controlled circulation, twin furnace	Controlled circulation, divided furnace	Supercritical combined circulation, divided furnace	Controlled circulation, divided furnace
No. of burners	3 elevations×8 corners =24	3 elevations×6 rows =18	5 elevations×8 corners =40	3 elevations×6 rows =18
Capacity of one burner (kcal/h)	32.86×10^6	52.02×10^6	38.93×10^6	40.02×10^6
Type of fuel atomization	Mechanical atomization —return system	Steam atomization	—	Steam atomization

TABLE IV
ANALYSIS OF COALS TESTED

NO.	COAL	PROXIMATE ANALYSIS				ULTIMATE ANALYSIS			HHV S.M.F. kcal/kg
		V.M. %	F.C. %	ASH %	F.C./V.M.	N DRY/DAF %	O DRY %	O/N	
1	SOUTH AFRICAN	25.3	55.0	17.0	2.17	1.6 (1.93)	10.8	6.75	6420
2	CHINESE	28.1	57.8	10.7	2.06	0.8 (0.9)	11.7	14.63	7020
3	JAPANESE	33.8	37.0	26.8	1.09	0.9 (1.23)	7.9	8.78	5850
4	SOUTH AFRICAN	31.3	51.6	13.2	1.65	1.7 (1.96)	13.3	7.82	6540
5	CHINESE	29.8	48.8	18.4	1.64	1.03 (1.26)	12.0	11.65	6330
6	JAPANESE	43.9	37.7	12.7	0.88	1.1 (1.26)	14.5	13.18	6370
7	AUSTRALIAN	30.7	54.2	11.9	1.77	1.6 (1.82)	9.1	5.69	6890
8	JAPANESE	46.4	37.3	10.7	0.80	1.1 (1.23)	14.1	12.82	6510

DEVELOPMENT AND FIELD OPERATION OF THE CONTROLLED FLOW/SPLIT-FLAME BURNER

By:

Joel Vatsky
Foster Wheeler Energy Corporation
9 Peach Tree Hill Road
Livingston, New Jersey 07039

ABSTRACT

An advanced low NO_x coal burner has been installed in a 375 MW front-wall fired steam generator. Unstaged NO_x levels below 0.4 lb/million Btu are being consistantly obtained with burners having a maximum liberation rate of 285 million Btu/hr. Prototype tests of this burner, in a 50 million Btu/hr test furnace, have resulted in unstaged NO_x emissions of 0.25 lb/million Btu; when staged using overfire air ports emissions were reduced below 0.20 lb/million Btu.

This high capacity low NO_x burner permits new steam generators to be equipped with the same number of burners and the same type of burner management system as were used prior to the advent of emission regulations.

The Foster Wheeler low NO_x system is also available for retrofit to older steam generators.

This availability is timely in that it provides an option for utilities, which must convert from oil to coal, to use a modern combustion system. This can be of particular importance to those units which were designed to fire "future coal", based on the boiler, firing system and performance coal availability of the 1950's and '60's, but have instead been firing oil. A further advantage may be provided by the large NO_x reductions attainable since these may permit trade-offs within the EPA's "bubble concept". However, the actual NO_x levels attainable for older units would be site-dependent.

INTRODUCTION

The nearly simultaneous imposition of emission controls and fuel restrictions on the design of power plants has resulted in a significant increase in the quantity of hardware which must be included between the fuel storage area and the stack. Coal, which is currently the only fuel permissible for new utility boilers in the U.S., now requires more extensive particulate and sulfur control equipment. Although this type of equipment is supplied by boiler manufacturers or their subsidiaries, the primary area of responsibility for the steam generator designer is that of NO_x control. Significant NO_x reductions, as compared to levels emitted prior to the advent of NO_x limits, can be attained by proper boiler and combustion system design.

A primary consideration in the design of low NO_x combustion systems should be attainment of minimum NO_x levels simultaneously with minimum increase in system complexity. Clearly, as more components are added to the overall power plant train it is desirable to maximize the availability of each component. Systems of reduced complexity result in lower first cost, decreased maintenance and simpler operation.

Foster Wheeler's method of minimizing boiler and firing system complexity is based upon the use of large capacity (up to 300 million Btu/hr) low NO_x coal burners which minimizes the number of burners required. The burner design and its flexibility and controllability permit a simple common windbox to be retained.

Foster Wheeler's first generation low NO_x burner, the Controlled Flow design, had been retrofitted in 1976 [1] to an older unit. NO_x was reduced about 50% (to 0.42 lb/10^6 Btu) without staging and to 0.3 lb/10^6 Btu with staging. More recently the advanced Controlled Flow/Split-Flame burner has been achieving un-

staged NO_x levels between 0.35 and 0.41 lb/10^6 Btu on a 375 MW steam generator to which it had been retrofitted.

If the EPA's research goals [2] can be used as a guide then even more stringent limits may be instituted in the future. These research goals are 200 ppm by 1980 and 100 ppm by 1985. Also in some states, units sold prior to 1971 are required to reduce NO_x emissions to below 0.7 lb/10^6 Btu.

In 1979, Foster Wheeler's experimental development program achieved NO_x levels below 0.2 lb/10^6 Btu, with the Controlled Flow/Split-Flame burner, in a 50 million Btu/hr research furnace. This development program and the field operation of this burner will be presented here.

NO_x EMISSIONS: EFFECT OF COAL CHARACTERISTICS AND BOILER DESIGN

The NO_x emissions from coal fired steam generators consist of three components:

- Thermal NO_x: formed by fixation of molecular nitrogen contained in the combustion air. This quantity is exponentially dependent on flame temperature; below about 2800°F the formation of thermal NO_x is negligible.

- Volatile and Char Fraction Fuel NO_x: formed from the atomic nitrogen which is chemically bound within the structure of the coal: nitrogen is contained in both the volatile and char fractions. NO_x formed from the volatile fraction is typically responsible for 75% of the fuel NO_x emission thereby being the largest component in the total emission.

These sources of NO_x can be controlled, to varying degrees, by proper boiler and firing system design. The NO_x level which is ultimately produced is dependent on numerous variables. The following is a discussion of those variables which are of primary consideration:

(a) Burner Zone Liberation Rate (Q/BZS): This is defined as the net heat input to the burner zone divided by the effective projected surface. This quantity has been discussed in detail previsouly [3,4]. Q/BZS affects flame temperature thereby determining the amount of thermal NO_x generated.

The boiler designer is provided with a useful tool for reducing NO_x by increasing burner zone surface (lowering Q/BZS). Reducing Q/BZS from 450,000 to 300,000 Btu/hr-ft^2, on units

equipped with high turbulent burners, lowers NO_x by about 30%.

(b) Firing Geometry: Opposed or Single Wall: Figure 1 is a summary of the NO_x emissions as a function of Burner Zone Liberation Rate for both single-wall and opposed-fired units. Both plots are composits of full load data from units all utilizing similar high turbulent intervane burners. It can be seen that, for any particular value of Q/BZS, opposed-firing always has lower NO_x emissions than does single-wall firing.

A third curve represents the NO_x variation with Burner Zone Liberation Rate (using the above definition and derived from published emission data [5,6,7] for tangential-fired boilers operated with overfire air ports closed. Although tangential firing has a lower uncontrolled NO_x emission, when compared with wall-fired boilers equipped with high-turbulent pre-NSPS* burners, the sensitivity to heat release rate appears to be greater. This differential is of no consequence when wall-fired units are equipped with modern low NO_x combustion systems.

Although this is useful information, the boiler's firing configuration cannot be dependent on NO_x requirements. The choice of boiler configuration is generally governed by the specified boiler capacity, economic considerations and plant requirements.

(c) Coal Characteristics: That part of the NO_x emission which is formed from the fuel-bound nitrogen is primarily dependent upon the percent fuel nitrogen content, heating value and volatility. The total nitrogen content is a function of both the percent nitrogen and heating value and can be expressed as lb NO_x/million Btu. Varying fuel characteristics will shift the curves of Figure 1 in the vertical direction.

*NSPS: NEW SOURCE PERFORMANCE STANDARD

Knowledge of the fuel nitrogen effect is important so that the designer can accurately determine the effect of various NO_x control measures. Foster Wheeler has developed such a technique. The uncontrolled NO_x level produced with the high turbulent intervane burner is determined to provide a baseline against which the effectiveness of NO_x reduction devices can be compared. Figure 2 illustrates the accuracy of the technique for four boilers equipped with intervane burners and staging ports for NO_x control. It can be seen that the baseline prediction method is quite accurate.

This prediction technique was modified in 1976 to incorporate the first generation low NO_x burner as the primary NO_x control method. The effectiveness of the newest low NO_x burner, the Controlled Flow/Split-Flame design, on a 375 MW front-wall fired unit, is shown for comparison.

Coal particle size distribution is also of importance for NO_x control. Good fineness has always been important from a combustion efficiency viewpoint. However, fineness can also have a significant impact on NO_x emission in low NO_x systems.

(d) Burner Characteristics: Flame conditions have a major impact on NO_x emissions. High turbulent burners which provide rapid mixing between the fuel and total combustion air and produce short intense flames will have the highest NO_x emissions. The rapid mixing increases flame temperature while simultaneously permitting the fuel-bound nitrogen to be liberated from the coal particles in an excess oxygen environment, thus promoting a relatively high fraction to be converted to NO.

The most effective means of reducing this conversion rate is to reduce the availability of oxygen to the fuel-found nitrogen. The two most practical means of accomplishing this are:

- Reduce burner air by use of staged combustion
- Controlled mixing of air and fuel at the burner

With a suitably designed burner, staged combustion can be used to provide additional NO_x reduction. However, coal properties must be carefully evaluated for any adverse effect on furnace conditions. Operation at burner stoichiometries below about 96-100% is, in general, not recommended.

NO_x CONTROLS AND THEIR EFFECTIVENESS

Prior to the advent of NO_x emission regulations the historical trend in burner and boiler design had been toward hot, high turbulent systems. Burners were designed to be as close to the premixed concept as possible in order to maximize flame temperature and minimize unburned carbon carryover. Figure 3 shows a typical 1965 vintage high turbulent intervane burner. A key reason for the excellent flame stability and high carbon burnout of this design is the annular coal nozzle and its tangential coal inlet.

The inlet/nozzle configuration produces a uniform coal distribution around the periphery of the nozzle outlet; there is no roping of the coal. The single register and throat geometry cause the coal/primary air stream to be rapidly entrained by the secondary air flow thereby maximizing the oxidizing regions of the flame. A short, hot flame results which has high thermal and fuel NO_x emissions.

The only operating control used with this type of burner is that which operates the register. In order to minimize the complexity of low NO_x systems, which must have increased numbers of components, it is advantageous to use the same type of control, scanning and ignition systems as were utilized on high turbulent burners.

High turbulent burners are amenable to NO_x reduction by controlling both flame temperature and oxygen availability to the coal.

Flame temperature can be reduced by:

- Increasing cooling surface (reducing Burner Zone Liberation Rate)
- Flue Gas Recirculation to the windbox (ineffective for coal firing)

Figure 1 has shown that NO_x emissions, from units equipped with high turbulent intervane burners, can be reduced by about 30% when Burner Zone Liberation Rate is decreased from 450,000 to 300,000 Btu/hr-ft^2.

The combination of reduced Burner Zone Liberation Rates and staged combustion was used as the NO_x control method for meeting the first EPA limits (0.7 lb/MMBTu) on units sold by Foster Wheeler until 1976.

Although effective in reducing NO_x emissions, staged combustion has two primary limitations:

- Tube wastage which occurs with high iron, high sulfur coals can affect unit life and reliability.
- Increased slagging which can affect unit availability.

These prolems tend to occur when the burner zone is operated substoichiometrically so that reducing atmospheres exist along the waterwalls. In order to avoid this situation we have limited burner stoichiometry to 96% minimum and incorporated BOUNDARY AIR TM to provide an oxidizing atmosphere along the walls in the burner zone. Figure 4 shows the location of the BOUNDARY AIR ports and slots. The locations were arrived at through the combined use of cold flow modeling of the lower burner zone and field experience. BOUNDARY AIR also acts as passive air flow balance technique to minimize slagging potential during load changes, mill out of service or unequal mill load operations.

The operational limits placed on staged combustion, so as to control wastage and slagging, inhibit its usefulness as a NO_x control measure. Consequently, a more flexible primary NO_x control technique was needed. This requirement has resulted in the development of the low NO_x controlled flow family of burners.

TM - A trademark of Foster Wheeler Energy Corporation

LOW NO_x BURNER DEVELOPMENT

A low NO_x burner development program was commenced in 1975. The primary goal was to develop a burner which would produce NO_x reductions greater than those attainable with overfire air ports. However, since the burner is only part of the overall system, requirements were also placed on compatability with the steam generator's design. These requirements can be summarized as follows:

- Burner capacity should be the same as that of the pre-NSPS high turbulent intervane burners (up to about 300 million Btu/hr).
- Excess air requirements and unburned carbon levels should be equal, and preferably superior, to those of the intervane burner.
- The common windbox should be retained to minimize secondary air system complexity.
- Combustion system controls and flame scanning should require no additional complexity.

Low NO_x Concept

Within a flame there is strong competition for O_2 between the carbon and nitrogen released from the coal. Under turbulent excess air conditions, substantially all of the carbon is oxidized to CO_2 whereas about 30% of the fuel nitrogen becomes NO, the remainder being emitted as molecular nitrogen (the conversion varies inversely with nitrogen content).

When the early phase of combustion occurs under reducing conditions, with sufficient residence time, the formation of NO is significantly reduced. In particular, when fuel devolatilization takes place in a reducing environment,

volatile-fraction fuel NO_x will be minimized. If the residence time in the reducing zone, or low excess air zone, is of sufficient duration, the char-fraction fuel NO_x will also be decreased. Also if the local flame stoichiometry is below about 95% theoretical air, the flame temperature will be depressed thereby reducing the formation of thermal NO_x. The reduction in flame temperature will also depend on the available cooling surface; a high Burner Zone Liberation Rate will prevent minimum NO_x levels from being obtained. The sensitivity of fuel NO_x to available oxygen level and mixing rates can be used advantageously to control NO_x via burner modifications.

Low NO_x Burner Functional Description

The test program has resulted in the successful development and field demonstration of two low NO_x burners: The Controlled Flow and the Controlled Flow/Split-Flame designs. As shown by Figure 5, the two burners are similar; the coal nozzle being the major difference. The burners operate in the following manner:

- Secondary Air Control

  A series register arrangement, common to both designs, allows simple burner controls to be used. The inner register, which regulates the degree of swirl around the coal nozzle, is controlled by a manual drive since continuous adjustment is not required.

  The outer register is controlled by a standard electric drive for operation at "closed", "ignite" and "Operate" positions. The register arrangement divides the secondary air into two concentric streams which independently vary swirl. The secondary air flows axially into the furnace with almost no component directed radially inward, toward the burner centerline. Two registers permit the mixing rate between the primary and secondary air streams, and the rate of entrainment of furnace gases, to be controlled.

  Note that both registers are well shaded from direct furnace radiation so that parts operate cooler and the tendency to warp or bind is minimized.

- Secondary Air Balancing

In order to maintain low levels of excess air while minimizing CO, unburned carbon and slag formation it is advantageous to attain a balanced secondary air flow to all burners. Foster Wheeler achieves this by measuring the pressure drop across the perforated plate air hood thereby obtaining an index of the secondary air flow to each burner. The flows are then balanced by positioning the axially movable sleeves which optimizes the secondary air distribution, both vertically and horizontally, in the windbox. The air hood also improves secondary air distribution around the periphery of the burner to minimize unwanted turbulence.

- Split-Flame Coal Nozzle

Coal is injected into the furnace through an annular nozzle which has been modified to separate the coal into concentrated streams, each of which forms an individual flame. Four streams are indicated in Figure 5 but the number is a design variable.

The split-flame nozzle minimizes mixing between the coal and the primary air. The combination of the concentrated coal streams and the staged secondary air produces near throat flame stoichiometries in the 60-70% range up to about two throat diameters into the furnace. At that point, the swirling secondary stream from the outer annulus,containing the remainder of the combustion air, combines the flames and provides sufficient mixing to ensure adequate carbon-burnout.

Uniform distribution of coal about the periphery of the annular passageway is attained, as with pre-NSPS burners, by use of the tangential coal inlet. There is no undersirable roping of the coal.

The basic Controlled Flow burner employs a tapered annular nozzle instead of a split-flame nozzle. The innner sleeve tip is axially movable thereby providing a means for varying the primary air velocity while primary air flow

is maintained constant. The velocity adjustment is used to optimize the primary air/secondary air velocity ratio which minimizes shear-induced turbulence.

The primary air velocity adjustment has also been incorporated into the Controlled Flow/Split-Flame burner.

The flows from both the Controlled Flow and the Controlled Flow/Split-Flame burners are axial and symmetrical about the burner axis. The only flow-induced turbulence is that which is deliberately provided by register swirl setting. This produces early staging of the flames with a minimum of unintentional mixing between the fuel particles and the combustion air.

Similarity to the Pre-NSPS Burner

After the low NO_x burners three manual adjustments are made(inner register setting, coal nozzle velocity and air hood sleeve) the respective mechanisms are locked. The burners then operate in precisely the fashion as would a pre-NSPS intervane burner. No additional controls are required, beyond the outer register drive. There are no feedback systems interlocked with the pulverizers and no continuous air flow controllers. Mills are taken in and out of service in exacly the same manner as on pre-NSPS boilers.

NO_x Emission Test Data

Development testing of our low NO_x combustion systems has been performed on a four-burner, 125,000 lb/hr steam generator that has been previously described in detail [1, 4]. More recently, additional testing has been performed on a 50 million Btu/hr single burner test facility [8, 9].

To summarize here:

The original Controlled Flow burner design achieved 35-40% NO_x reductions on the four-burner unit. The design was then modified, scaled-up and tested on a utility steam generator.

This first field installation was a retrofit of a 265 MW opposed-fired unit in Japan. The work was performed by Foster Wheeler's Japanese licensee,

Ishikawajima-Harima Heavey Industries Co. (IHI), in 1976. Figure 6 summarizes the NO_x results obtained: 45-50% NO_x reduction with overfire air ports closed, 65-70% with overfire air ports open (at a burner stoichiometry of 96%). Similar results were obtained in the sister unit when it was retrofitted in 1977.

It should be noted that, prior to installation of the Controlled Flow burner, these units had slagging problems which were made worse by staging for NO_x control. When the low NO_x burners were installed, Boundary Air was simultaneously added. The combination of the cooler flames produced by the Controlled Flow burner and the oxidizing atmosphere maintained along the lower furnace walls by Boundary Air has significantly alleviated the slagging problem. The units can now operate continuously with overfire air ports open.

It is interesting to note that overfire air is still effective in combination with the low NO_x burner. This is however, as expected, since the two stage effect, with the burners operated at approximately the stoichiometric ratio, permits most of the char to burn out in a low excess air environment. Consequently, as nitrogen is released from the char it has a greater tendency to form N_2 than NO. The greater the separation between the overfire air ports and the burner zone, the greater the residence time at low O_2 and the lower the NO_x level will be.

All low NO_x burners developed by Foster Wheeler, including the most advanced designs, can still be used in conjunction with overfire air ports. NO_x can be reduced an additional 25-30% when burner stoichiometry, at 20% excess air, is reduced from 120% theoretical air to about 100%. For this reason overfire air ports may still be considered on a case-by-case basis, as a supplementary NO_x control measure as required by coal characteristics and emission limits. However, it must be reiterated that the degree of staging is generally limited because of its potentially adverse effect on slagging and tube wastage.

The Controlled Flow burner produces a flame shape which is similar to, although slightly longer than, that of the high turbulent intervane burner. The similarity of flame shapes and simplicity of design permits the Controlled Flow burner to be retrofitted to many pre-NSPS steam generators on a plug-in basis.

This is confirmed by the success of the retrofit installations of this burner in Japan; the units there being 10 years old at the time of the retrofit.

Functionally the Controlled Flow burner reduces NO_x by minimizing turbulence and mixing between the primary air/coal stream and the secondary air. Although only sufficient turbulence is generated to maintain flame stability, the initial mixing between primary air and coal and the inner secondary air flow results in near-throat flame stoichiometry of about 85-90%. This is sufficient to yield 40-50% NO_x reductions and is equivalent to operating a high turbulent burner, at the same stoichiometry, in conjunction with overfire air ports.

Figure 7 compares the NO_x reduction attainable from the intervane burner, when staged, to the Controlled Flow burner unstaged and staged, as a function of near throat burner stoichiometry. It can be seen that as the Controlled Flow burners' stoichiometry is reduced by staging (with overfire air ports) from 120% to 96%, the attainable NO_x reduction is increased from about 50% to about 65-70%.

In order to attain greater NO_x reductions, it is therefore desirable to reduce the near-throat flame stoichiometry. Since the Controlled Flow burner is a dual register type which two-stages the secondary air, it does not control the mixing or the distribution of the primary air and coal. If the coal can be substantially separated from the primary air and concentrated (i.e., fuel-side staging) then the Controlled Flow burner will be essentially triple-staged. Near-throat flame stoichiometries of about 60-70% should thus be attainable and would provide NO_x reductions of at least 65%.

The split-flame coal nozzle is one method of achieving this goal and has been successfully developed by Foster Wheeler. Development of the initial design concept [1] on the 125,000 lb/hr industrial steam generator and <u>initial</u> field operation [8, 9] have been discussed in detail previously. This design is effective, functionally, in reducing NO_x 55-60% as shown by Figure 8 for the development tests and Figure 9 for the early field tests.

Figures 10 and 11 are photographs the flames developed on the test boiler and the utility boiler respectively.

The original split-flame design did not incorporate a mechanism for primary air velocity control. The new design, which is now in use commercially and whose operation was described above, now contains this control.

The new burner, which is best described as the Controlled Flow/Variable Velocity Split-flame (CF/SV) design, has been prototype tested on a 50 million Btu/hr test facility and has been successfully scaled-up to full size utility scale. In order to evaluate the performance of the CF/SV design on the test furnace the two earlier burner designs, the Controlled Flow and original Controlled Flow/Split-Flame design, were also tested. These burners provided a basis against which the CF/SV design was compared.

The results of these tests are summarized in Figure 12. It can be seen that the original split-flame design reduces NO_x 35% below the Controlled Flow burner with annular nozzle; the new nozzle design incorporating the variable velocity feature reduces NO_x 50% below the Controlled Flow burner.

For comparison, three full load data points from the 125,000 lb/hr four-burner boiler are also included in Figure 12. They represent the NO_x levels attained by the intervane burner, the Controlled Flow Burner and the Controlled Flow/Split-Flame (original design) burner. Agreement between the single burner test facility and the four-burner industrial boiler is excellent.

Figure 13 is a photograph of the flames produced by the Split-Flame nozzle and Figure 14 is a photo of the flames from the Variable Velocity Split-Flame nozzle. The new design produces more distinct flames with a greater included angle. Furnace observations indicate the flame's length is somewhat shorter than with the original Split-Flame design. This represents an improvement on an already good situation since there was no flame impingement on the rear wall of the actual utility boiler tested.

FIELD DEMONSTRATION OF THE SPLIT-GLAME CONCEPT

The utility boiler referred to above is the San Juan #1 unit of Public Service Co. of New Mexico. The original split-flame design was retrofitted to this unit in November 1978; the new Controlled Flow/Split-Flame (CF/SV) burner was retrofitted in November 1979 and has been performing satisfactorily, and meeting all design and performance goals, since then.

The boiler is a front-wall fired unit with 16 burners, each of which has a maximum capacity of 285 million Btu/hr, arranged in a 4 x 4 matrix. Four Foster Wheeler medium speed MB pulverizers are used. The boiler can achieve full load with any three pulverizers in service. The fuel used is a high has New Mexico sub-bituminous coal, with heating value typically in the 9,000-10,000 Btu/lb range; although coal with heating value as low as 8,000 Btu/lb has been fired successfully.

Figure 15 compares the emissions attained on San Juan #1 with the results achieved on the test furnace. A reduction over 65% is being achieved in the field, which is quite similar to the reduction achieved on the prototype. This indicates that the scale-up parameters developed (scale-up ratio is 6:1) are accurate.

The Controlled Flow/Split-Flame concept produces significantly greater NO_x reductions than does a dual register type of burner when there is no staging of the throat. However, when the burner is staged, NO_x can be reduced an additional 25% to 30%.

On the test furnace, NO_x is reduced to 0.185 lb/10^6 Btu when overfire air ports are open with the Controlled Flow burner and the new Variable Velocity Split-Flame nozzle; with CO increasing to about 125 ppm. This is a 65% reduction from the level measured with the Controlled Flow burner, and 77% from the

pre-NSPS intervane burner level. But, as shown on Figure 15, the asymptotic decrease in the attainable NO_x levels may imply that a practical floor is being approached.

Figure 16 summarizes and compares the results of the low NO_x burner conversions on the 265 MW opposed-fired unit and the 375 MW front-wall fired San Juan unit. Although there is a differential of about 0.25 $lb/10^6$ Btu between the uncontrolled NO_x levels, the low NO_x burners reduce the differential to less than 0.1 $lb/10^6$ Btu. Note also that the primary reason that the San Juan emission is higher than the boiler in Japan is that the former is single-wall fired and the latter is opposed fired. Other variables,such as Burner Zone Liberation Rate and coal characteristics, are important but secondary in influence.

Figure 16 also contains the test results from the 50 million Btu/hr test furance from which the burner in use at San Juan #1 was scaled. This data comparison clearly shows the advantages of the Controlled Flow/Split-Flame concept.

The effectiveness of the air hood and sleeve is demonstrated in Figure 17 which shows the necessity for horizontal adjustment of the air distribution in the windbox. With all burners adjusted equally (all air hoods and swirl vanes at the same settings), CO stratified along the sidewalls while O_2 and NO_x peaked in the center of the furnace where CO was zero. After balancing the secondary air, by adjusting the air hoods' sleeves to obtain equal pressure drops across all air hoods, a nearly uniform gas distribution was obtained across the furnace. This permitted the unit to operate at lower exess air with reductions in both NO_x and CO.

THE LARGE CAPACITY BURNER'S SIGNIFICANCE

New Equipment Design

The large capacity Controlled Flow/Split-Flame low NO_x burner, which emits NO_x levels at least 60% below those of high turbulent burners, increases the flexibility of the steam generator designer. The design constraints and added costs imposed by a large number of small burners are alleviated.

Figure 18 summarizes the low NO_x combustion system for a typical 600 MW coal-fired steam generator. The following enumerates the advantages provided by the large capacity Controlled Flow/Split-Flame low NO_x burner design.

1. A simple common windbox can be retained because the secondary air flow to each burner can be measured and controlled. It is not necessary to modulate the air hood sleeves when pulverizers are taken in and out of service or operated unequally loaded or when load is changed.

2. Lower furnace geometry can be made less dependent on the requirements of the burner. The economics of size, arrangement of heat absorbing area and NO_x requirements can be more advantageously balanced.

3. Standard flame sensing, ignition and control equipment can be used: one electric register drive per burner with no auxiliary controls required. The combustion control system is the same as that for a pre-NSPS boiler.

4. Only two sets of movable vanes per burner: 600 MWe boiler would have 24 - 250 MMBtu/hr burners (48 sets of vanes) versus 48 to 60 small burners (96-120 ets of vanes, assuming only two sets of movable vanes per burner).

5. Burner design is such that no secondary air control vanes receive direct radiation from the flame: parts operate cooler and are less likely to overheat and bind.

6. Pulverizer controls and conduit designs are greatly simplified due to the reduced number of burners. Therefore, there are fewer areas subject to erosion which results in reduced maintenance requirements over the unit's life.

7. The BOUNDARY AIR system provides a passive means of maintaining an oxidizing atmosphere along the sidewalls and in the hopper: during unit operation it is not necessary to modulate any dampers as load changes or as mills are taken out of service. This system is now standard on all Foster Wheeler units, even those where slagging is not expected to be a problem, since it also reduces CO formation during low NO_x operation.

8. Although slightly longer than the high turbulent flame produced by the pre-NSPS intervane burner, the relatively short flame produced by the high capacity Controlled Flow/Split-Flame burner permits this low NO_x design to be amenable to further NO_x reduction via the use of overfire air ports. However, the use of overfire air must be considered on a case-by-case basis since fuel quality and properties must be carefully evaluated.

Retrofit Capability to Older Boilers

The Controlled Flow and Controlled Flow/Split-Flame burners can be designed over the capacity range of pre-NSPS equipment; up to a maximum burner liberation of 300 million Btu/hr. Since these burners are identical, except for the design of the coal nozzle and their resultant NO_x capabilities, and require no special windbox, structural modifications or additional controls, they can be installed on a plug-in basis in most units equipped with circular burners. Units equipped with other types of burners may require pressure part changes.

The retrofit capability of these burners is due both to the flexibility and controllability designed into them and to their relatively short flame lengths. The flame envelope of the Controlled Flow design is nearly identical to that of the pre-NSPS Intervane burner; that of the split-flame design is slightly longer. Flame envelope and length can be modified by adjusting register settings and primary air velocity.

Other advantages of this system, which combines a modern low NO_x burner with BOUNDARY AIR and is essentially the same as that which is now offered for new equipment, <u>exclusive</u> of low NO_x are:

1. Cooler, less turbulent, flames.
2. Improved balance of secondary flows to yield less variation in burner-to-burner stoichiometries.

These should permit:

- Lower excess air operation for improved efficiency.
- Decreased slagging for improved availability.

The degree of improvements in operation which could be afforded to older equipment would obviously depend on the situation of the individual unit concerned.

SUMMARY

A prototype advanced low NO_x burner, the Controlled Flow/Split-Flame design, has demonstrated NO_x reduction of 65% without staging (to a level of 0.25 lb/million Btu) and up to 77% with staging (to a level of 0.185 lb/million Btu). This burner has been successfully scaled-up and retrofitted to a 375 MW front-wall fired steam generator where NO_x emissions below 0.4 lb/million Btu, also representing a 65% reduction, have been consistently obtained without the use of overfire air. This design is now the standard offering for new Foster Wheeler steam generators.

The Controlled Flow/Split-Flame burner, and the earlier Controlled Flow design, are capable of being retrofitted to older steam generators. Both are in successful field operation in retrofitted units.

REFERENCES

1. Vatsky, J., "Attaining Low NO_x Emissions by Combining Low Emission Burners and Off-Stoichiometric Firing", presented at the 70th Annual Meeting of the American Institute of Chemical Engineers, November, 1977.

2. Mason, H. B. and Waterland, L. R., "Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies.: Proceedings of the Second Stationary Source Combustion Symposium, Vol. 1, EPA-600/7-77-073a, July, 1977.

3. Sommerlad, R. D., R. P. Welden, and R. H. Pai, "Nitrogen Oxide Emission, An Evaluation of Test Data for Design", presented at the 66th Annuall Meeting of the American Institute of Chemical Engineers, Philadelphia, Pennsylvania, November, 1973.

4. Vatsky, J., "Experience in Reducing NO_x Emissions on Operating Steam Generation:, Presented at the Second NO_x Technology Seminar, Denver, Colorado, November 8 and 9, 1978.

5. Selker, A. P., "Program for Reduction of NO_x from Tangential Coal-Fired Boilers Phase II" Combustion Engineering Inc., Windsor, Connecticut, Environmental Protection Technology Series Report EPA-650/2-73-005-1.

6. Bartok, W., Crawford, A. R. Manny, E. H., "Control of Utility Boiler and Gas Turbine Pollutant Emissions by Combustion Modification - Phase I", Exxon Research and Engineering Company, Linden, New Jersey, Interagency Energy - Environment Research and Development Series Report EPA-600/7-78-036a.

7. Burrington, R. L., Cavers, J. D., Selker, A. P. "Overfire Air Technology for Tangentially Fired Utility Boilers Burning Western U.S. Coal" Combustion Engineering Inc., Windsor, Connecticut, Interagency Energy - Environment Research and Development Series Report EPA-600/7-77-117.

8. Hansen, A.M., H. Ikebe, "Significant Developments to Limit NO_x Formation in Steam Generators", presented at the Joint Power Generation Conference, October, 1979.

9. Vatsky, J., "Modern Combustion Systems for Coal-Fired Steam - Generators" Presented at the Pacific Coast Electric Association Conference, San Francisco, California, March, 1980.

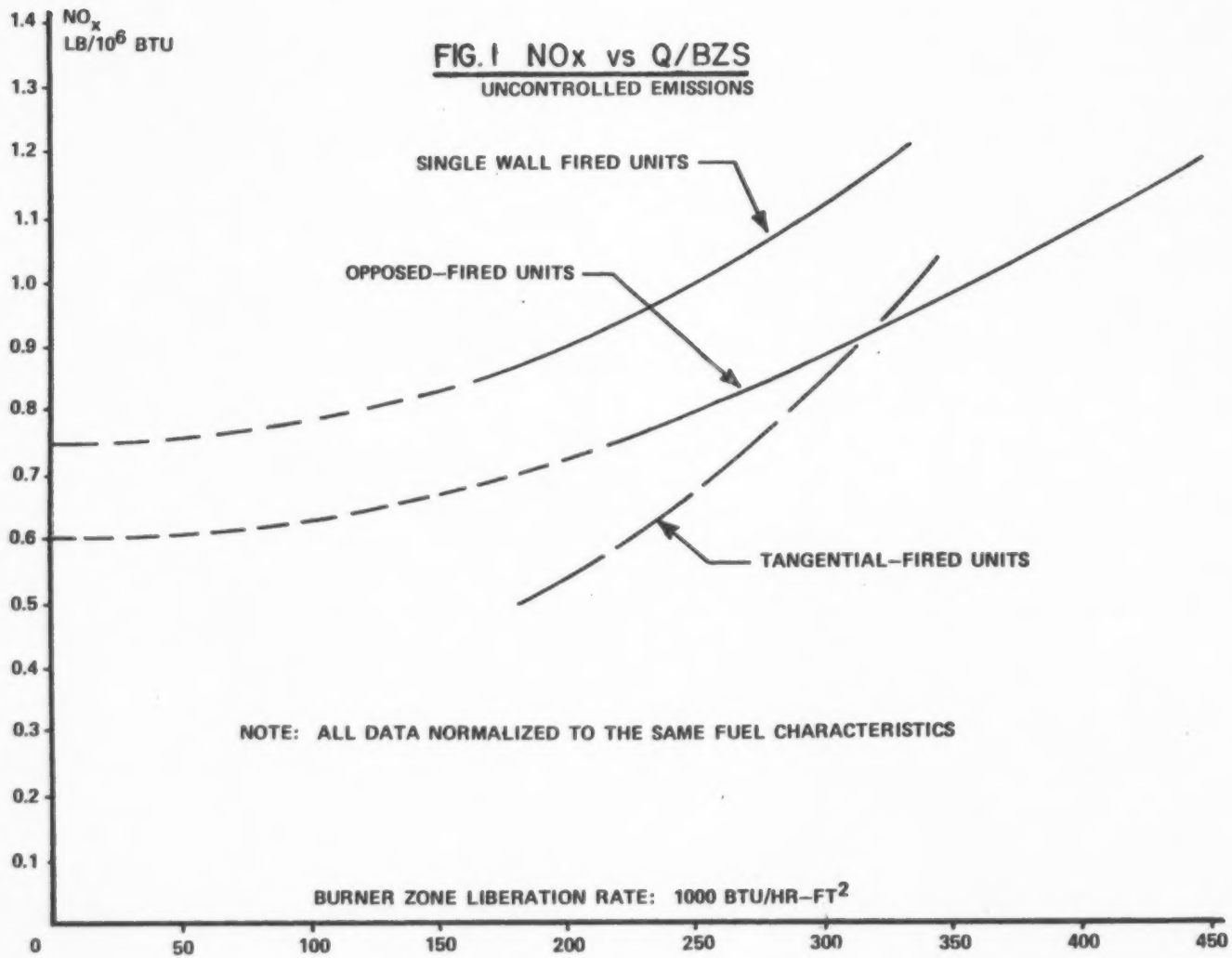
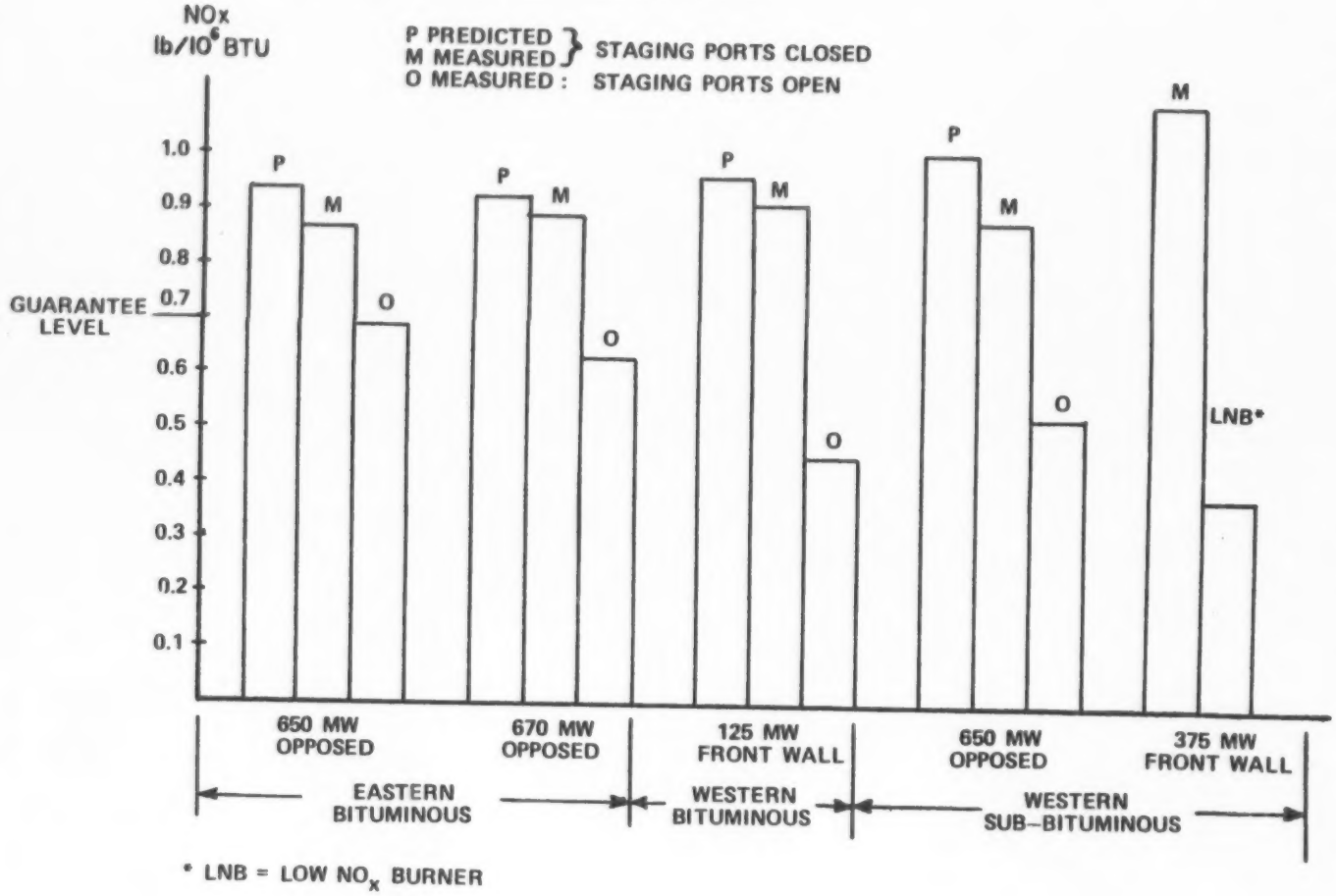
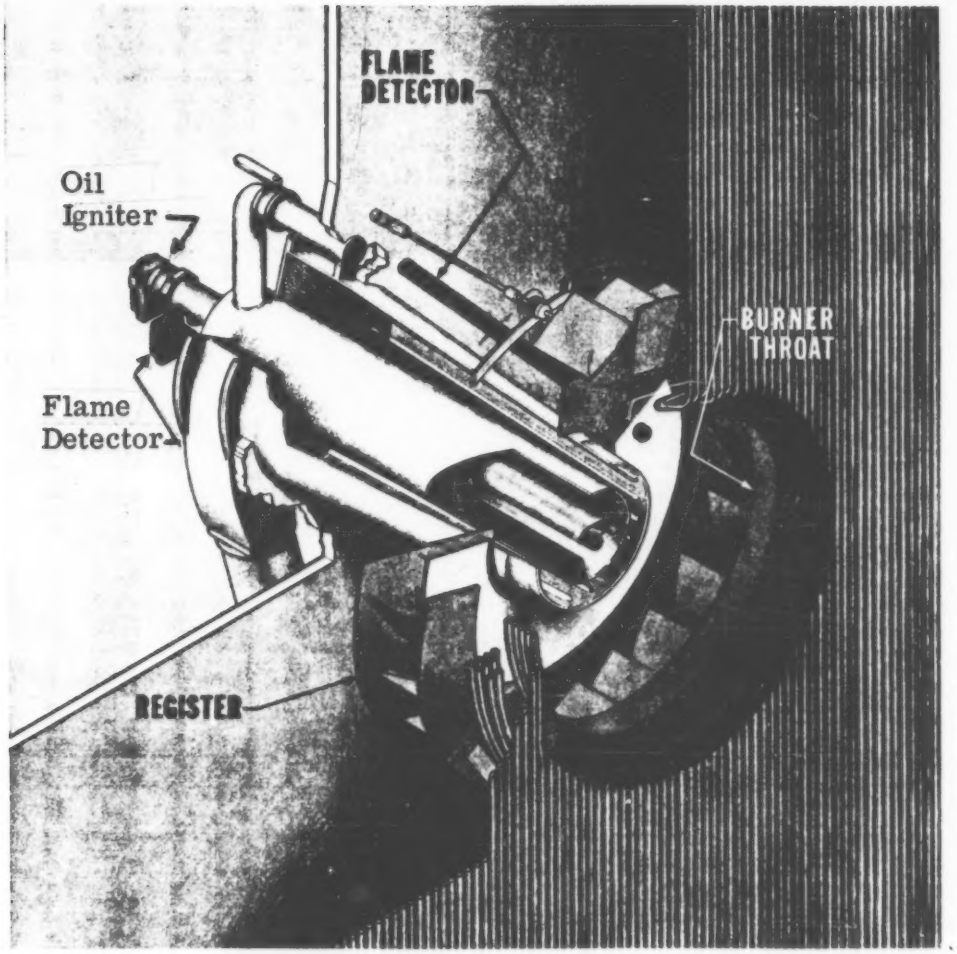


FIG. 1 NOx vs Q/BZS
UNCONTROLLED EMISSIONS
NO_x LB/10^6 BTU
1.4
1.3
1.2
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
50
100
150
200
250
300
350
400
450
SINGLE WALL FIRED UNITS
OPPOSED–FIRED UNITS
TANGENTIAL–FIRED UNITS
NOTE: ALL DATA NORMALIZED TO THE SAME FUEL CHARACTERISTICS
BURNER ZONE LIBERATION RATE: 1000 BTU/HR–FT^2

FIGURE 2 PREDICTED VS. MEASURED NO_x



* LNB = LOW NO_x BURNER



INTERVANE BURNER

FIG. 3

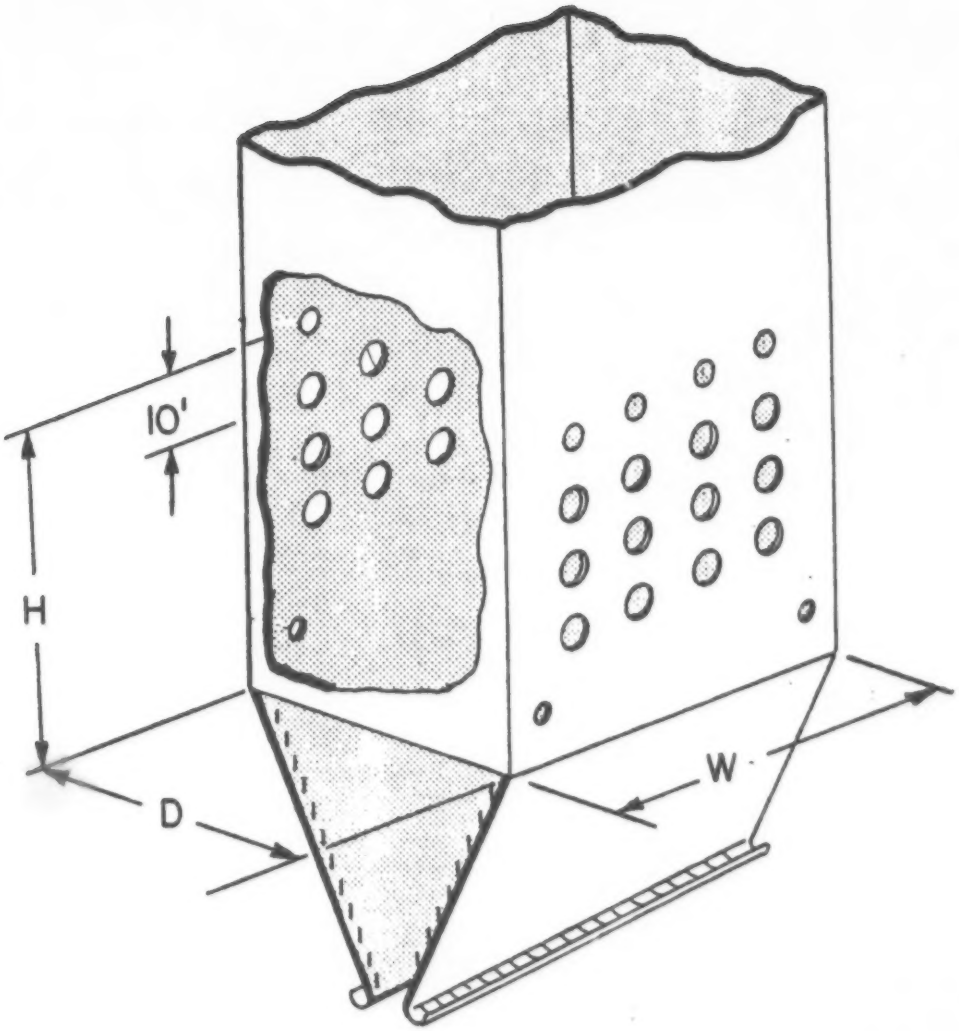


FIG. 4 FLAME BASKET OF TYPICAL LARGE BOILER-BURNER ZONE SURFACE DEFINED BY H. D. AND W.

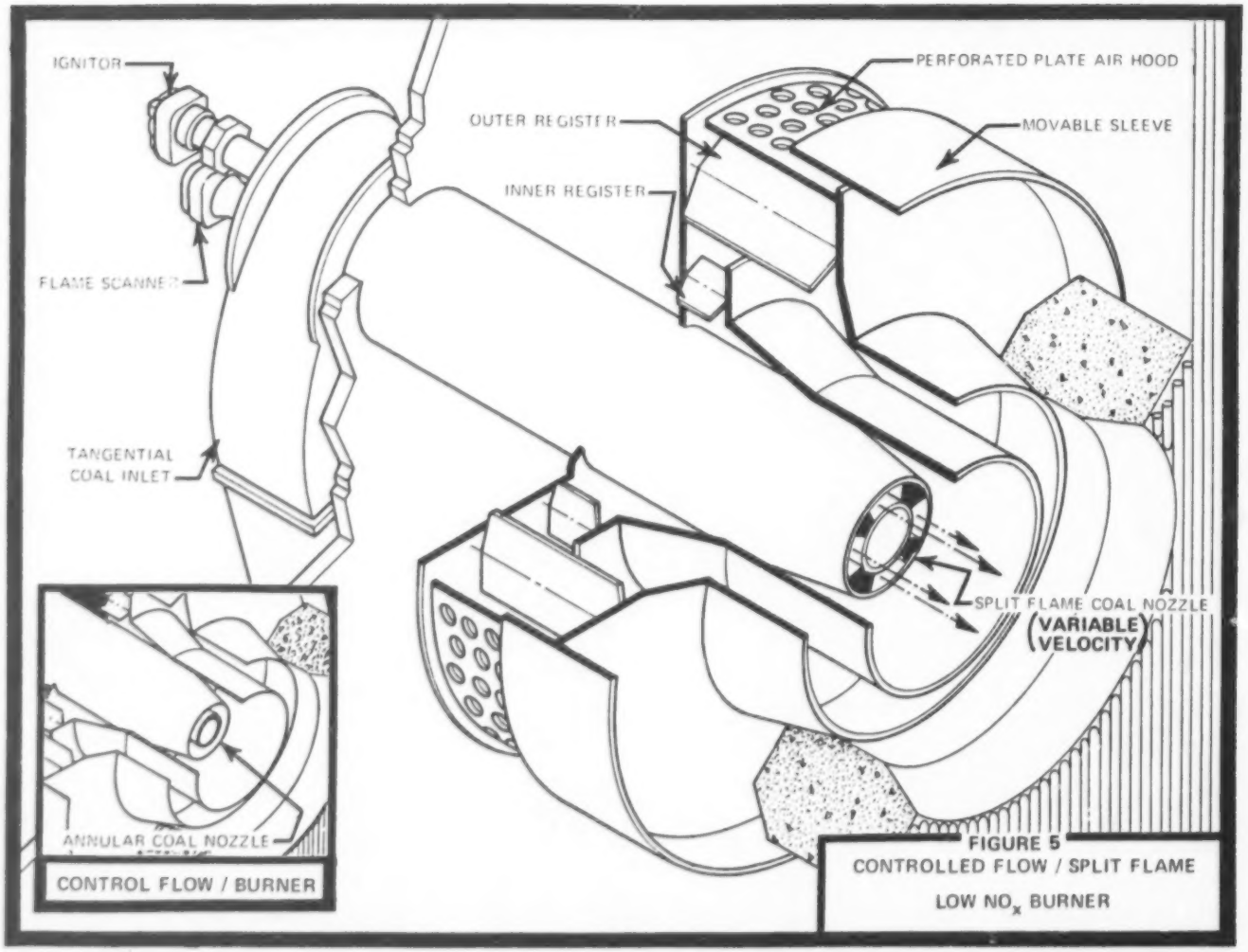


FIGURE 5
CONTROLLED FLOW / SPLIT FLAME
LOW NO_x BURNER

FIG. 6: NO_x EMISSIONS

265 MW_e UTILITY BOILER

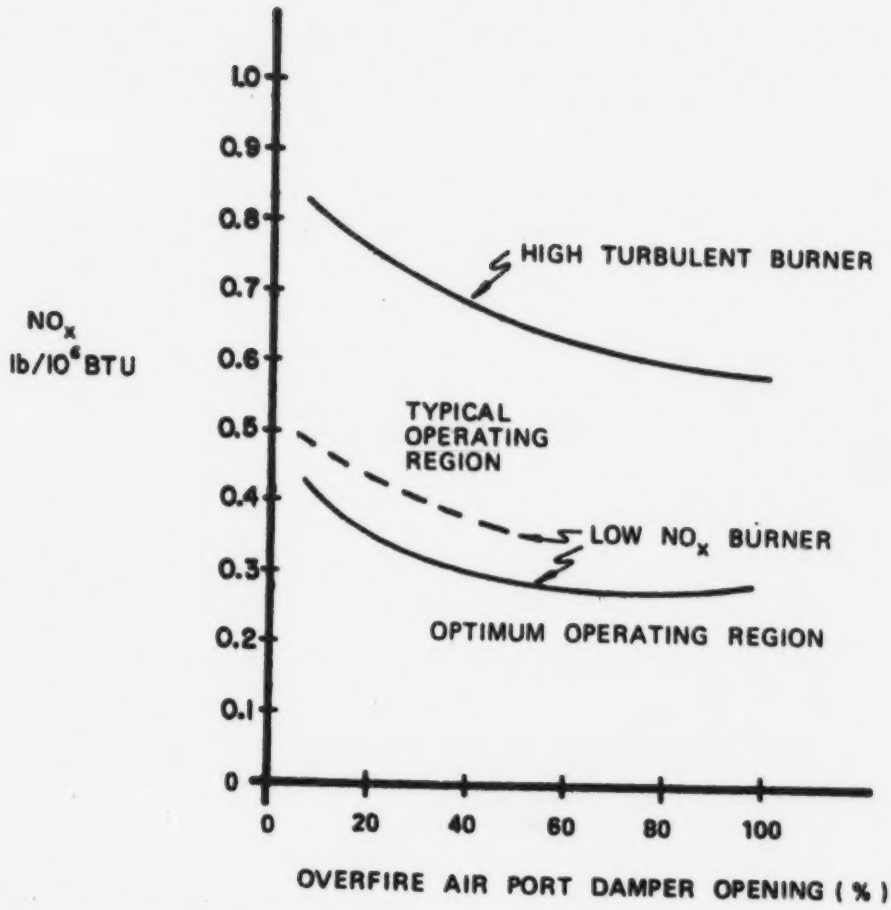


FIG. 7 NOx REDUCTION WITH STAGING

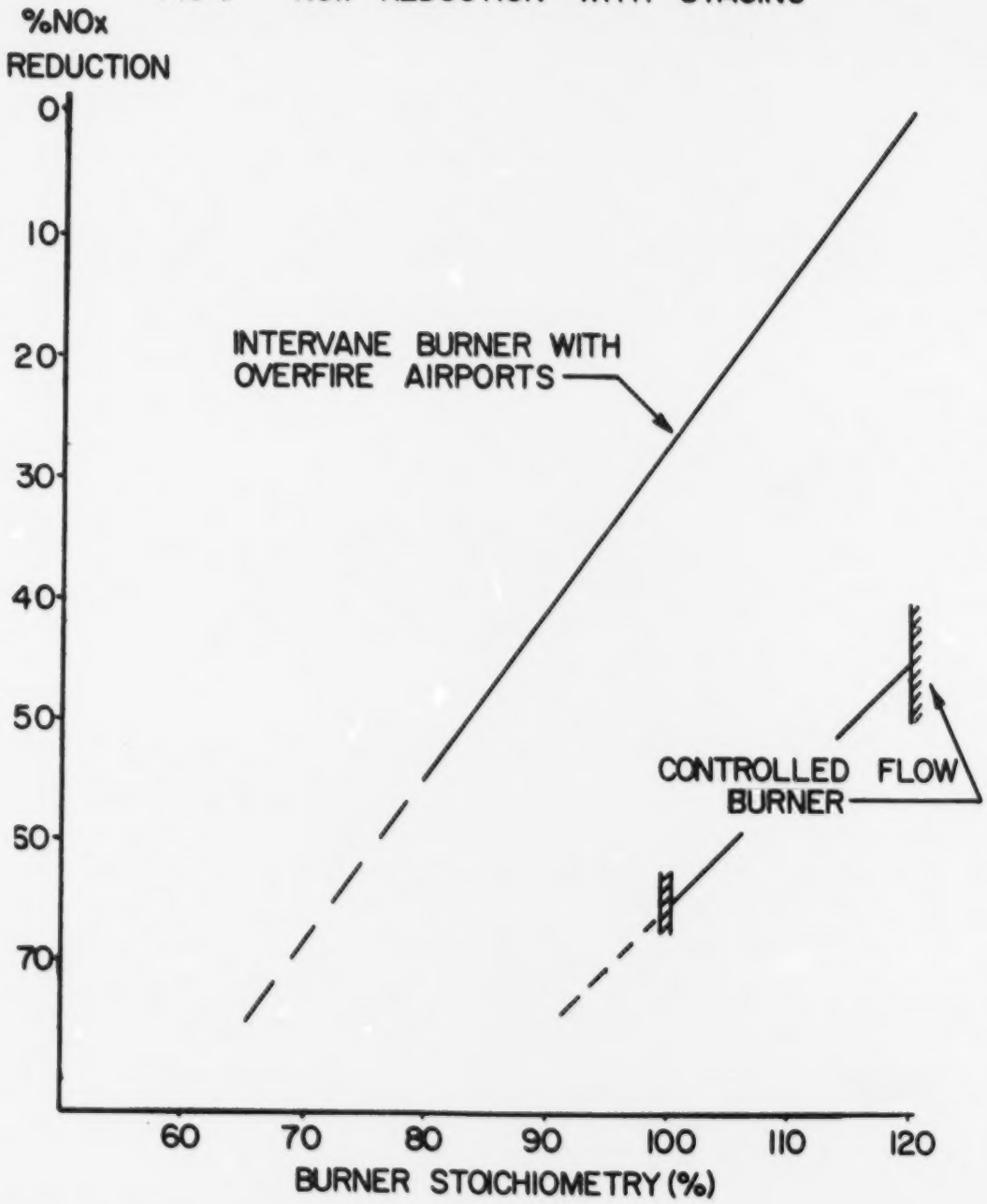


FIG. 8 : NOx vs LOAD

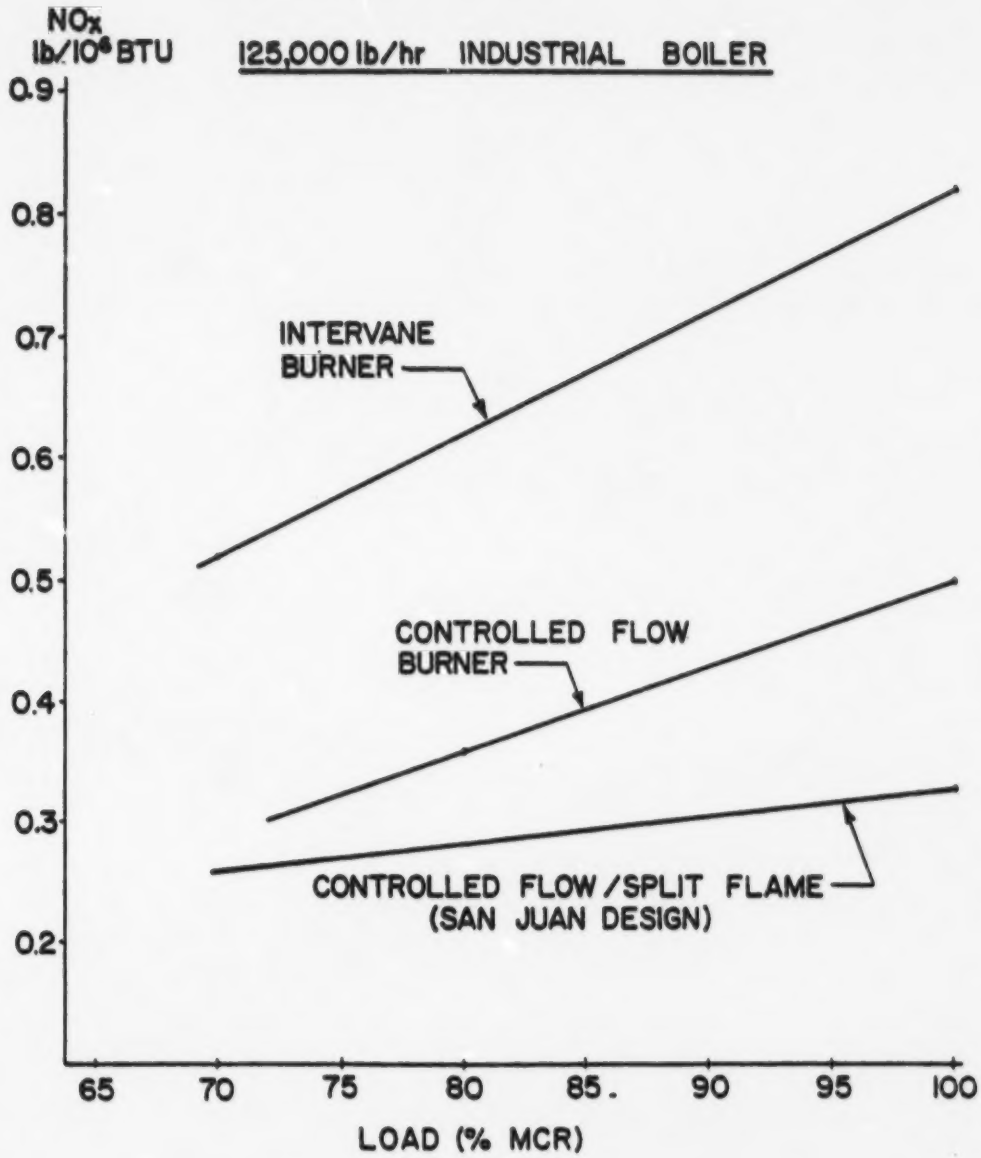
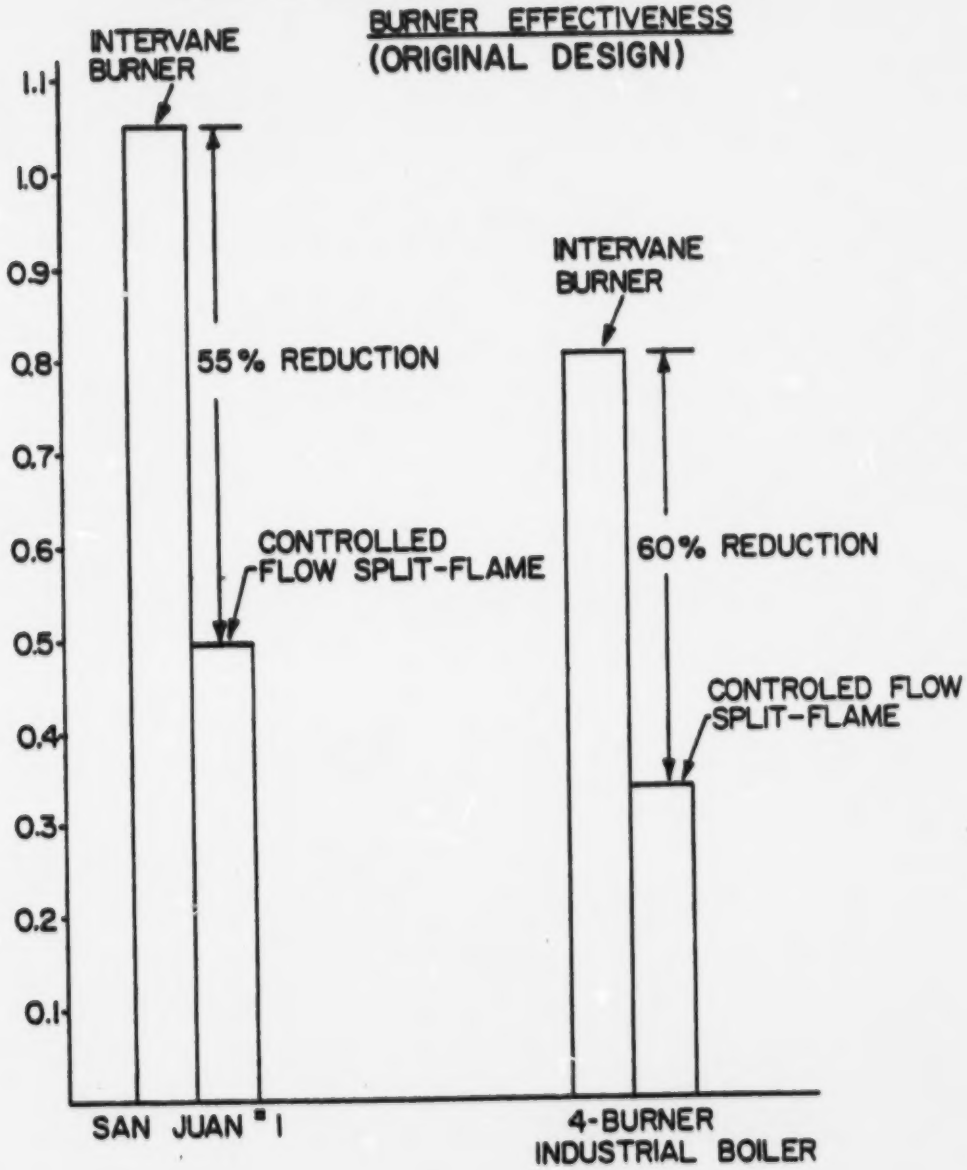


FIG. 9 : CONTROLLED FLOW/SPLIT-FLAME

BURNER EFFECTIVENESS
(ORIGINAL DESIGN)



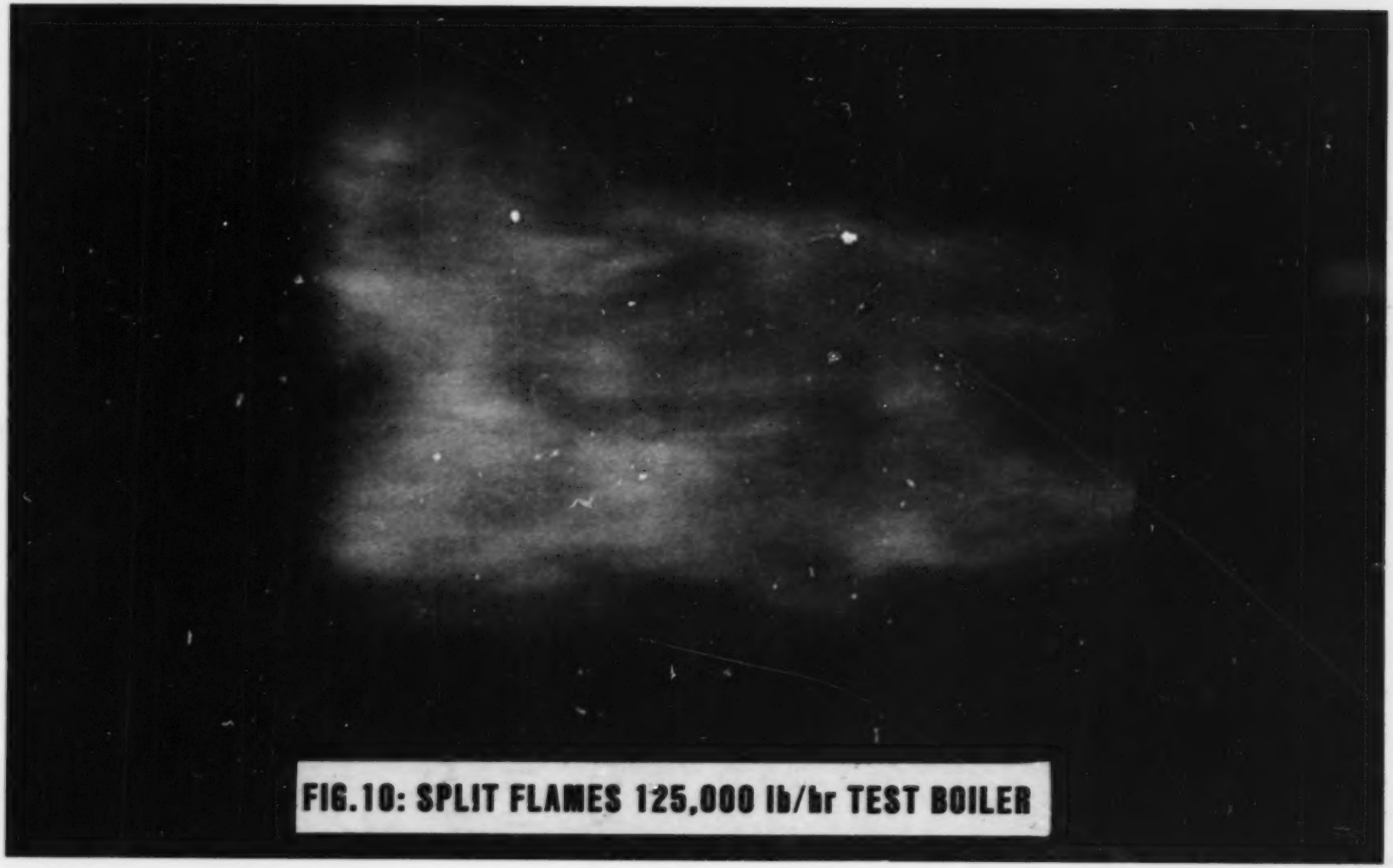


FIG.10: SPLIT FLAMES 125,000 lb/hr TEST BOILER

FIG. 11: SPLIT FLAMES SAN JUAN #1 BURNER

FIG. 12: NOx COMPARISON
SPLIT-FLAME BURNER TIP

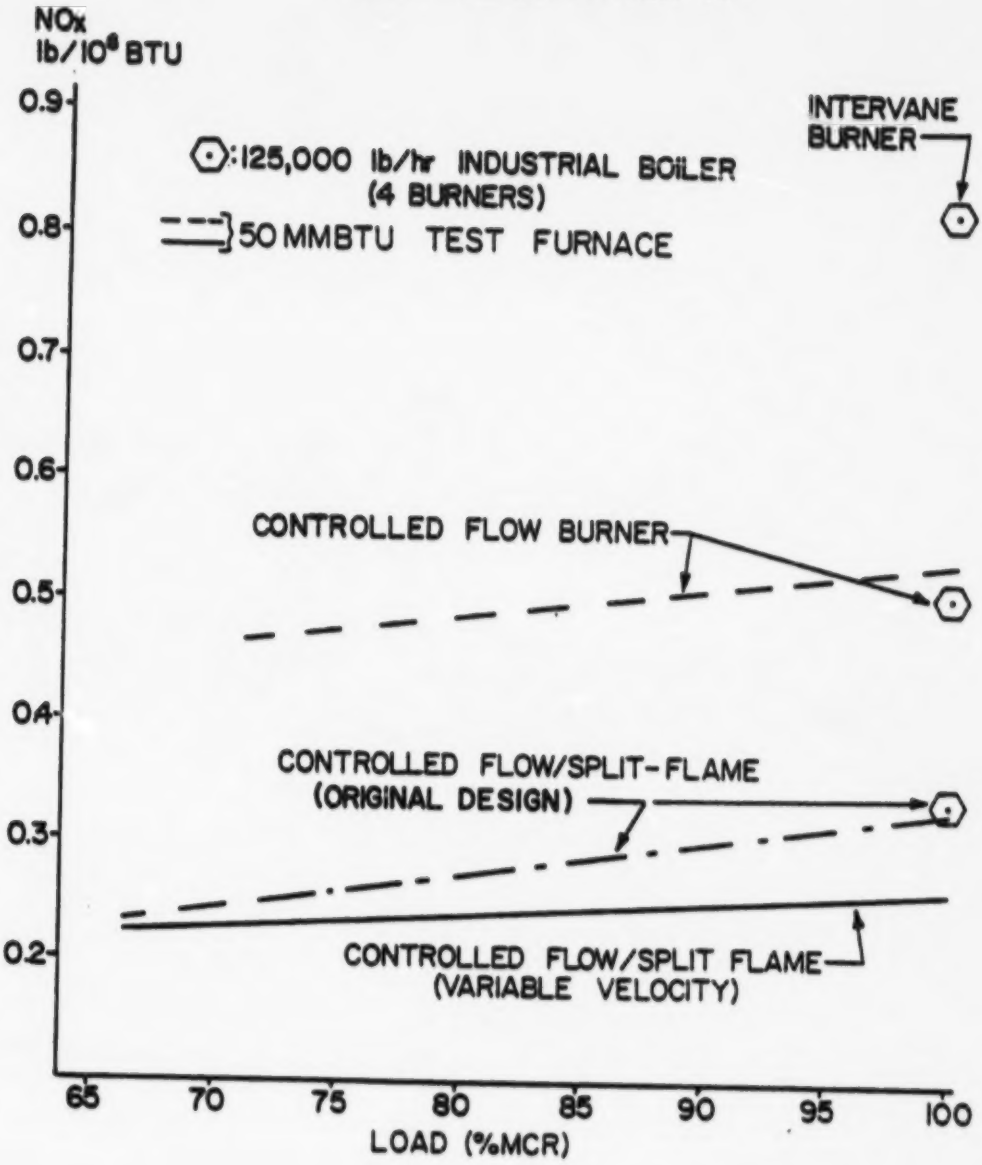


FIG. 13: TEST FURNACE SPLIT-FLAMES
(ORIGINAL DESIGN)

FIG. 14: TEST FURNACE SPLIT-FLAMES
(VARIABLE VELOCITY DESIGN)

FIG. 15: LOW NOx BURNER NOx COMPARISON

KEY
IV = INTERVANE BURNER
CF = CONTROLLED FLOW
CF/S = CONTROLLED FLOW/SPLIT FLAME
CF/SV = CONTROLLED FLOW/SPLIT FLAME (VARIABLE VELOCITY)

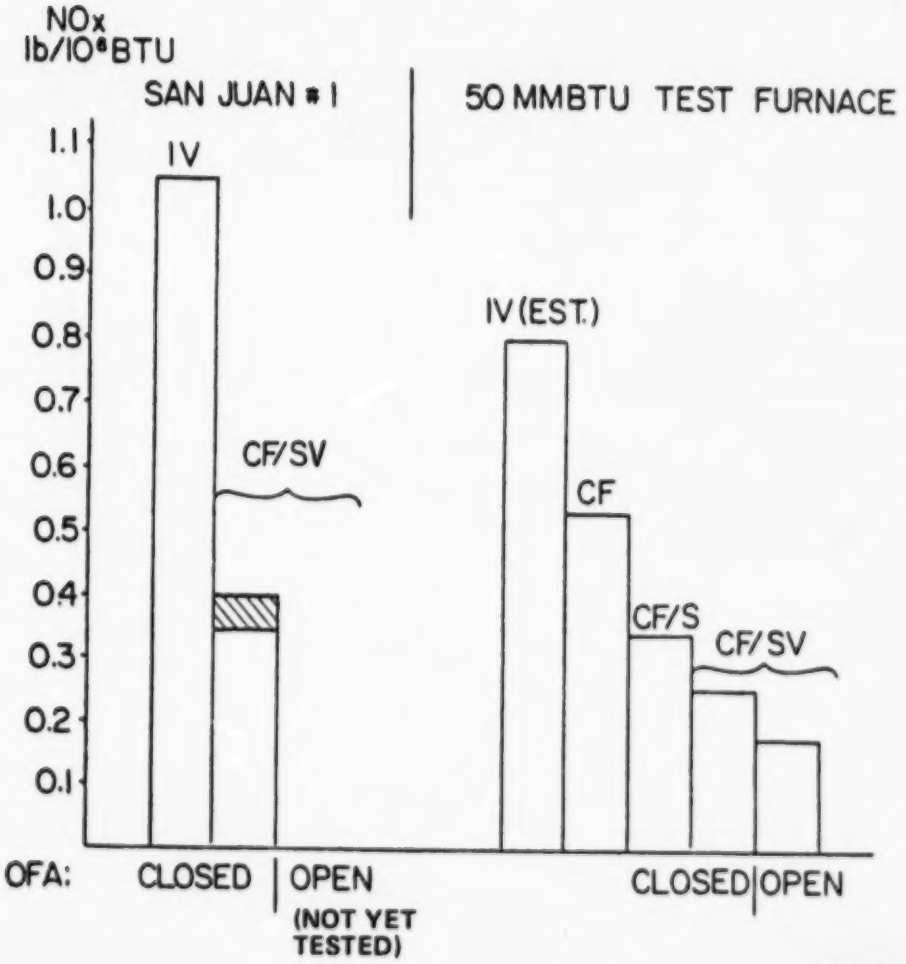
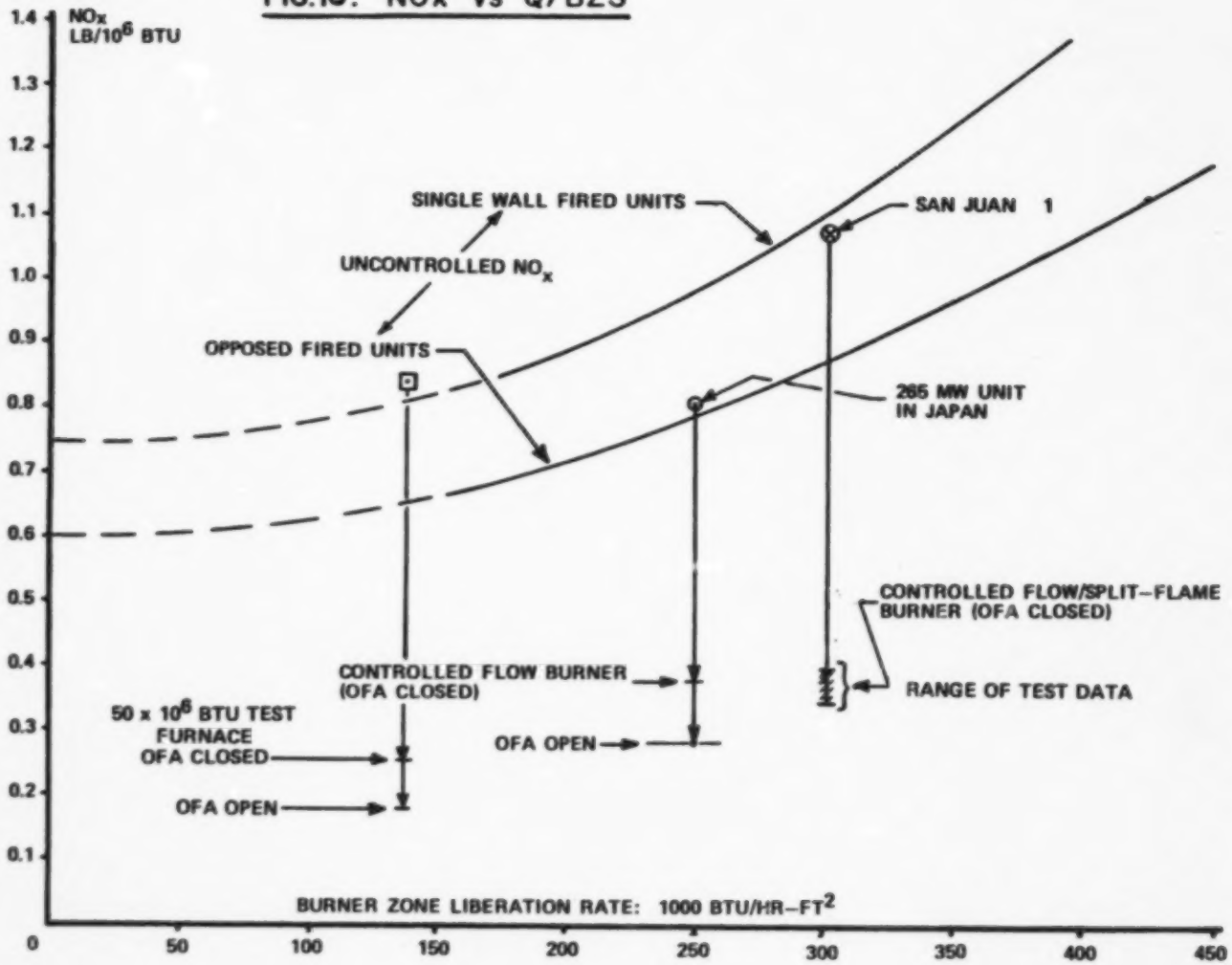


FIG. 16: NOx vs Q/BZS



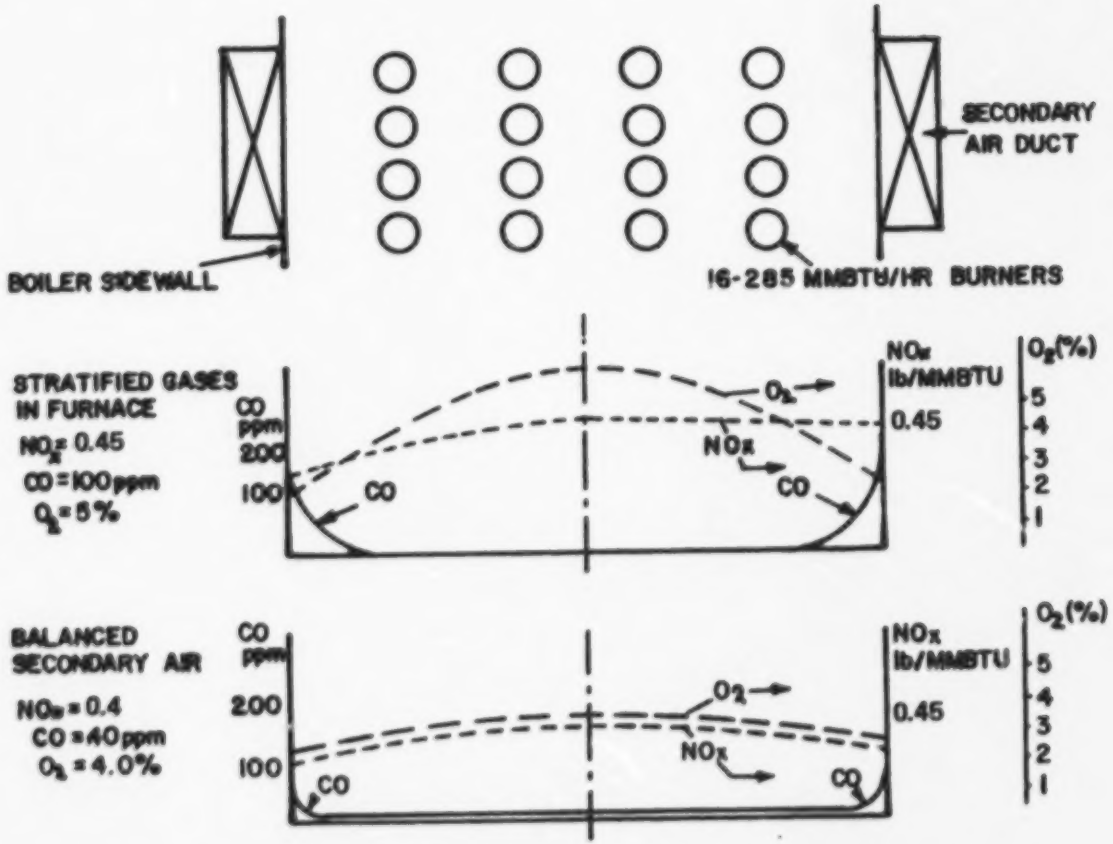


FIG. 17 EFFECTIVENESS OF SECONDARY AIR BALANCING SYSTEM (375 MWe STEAM GENERATOR)

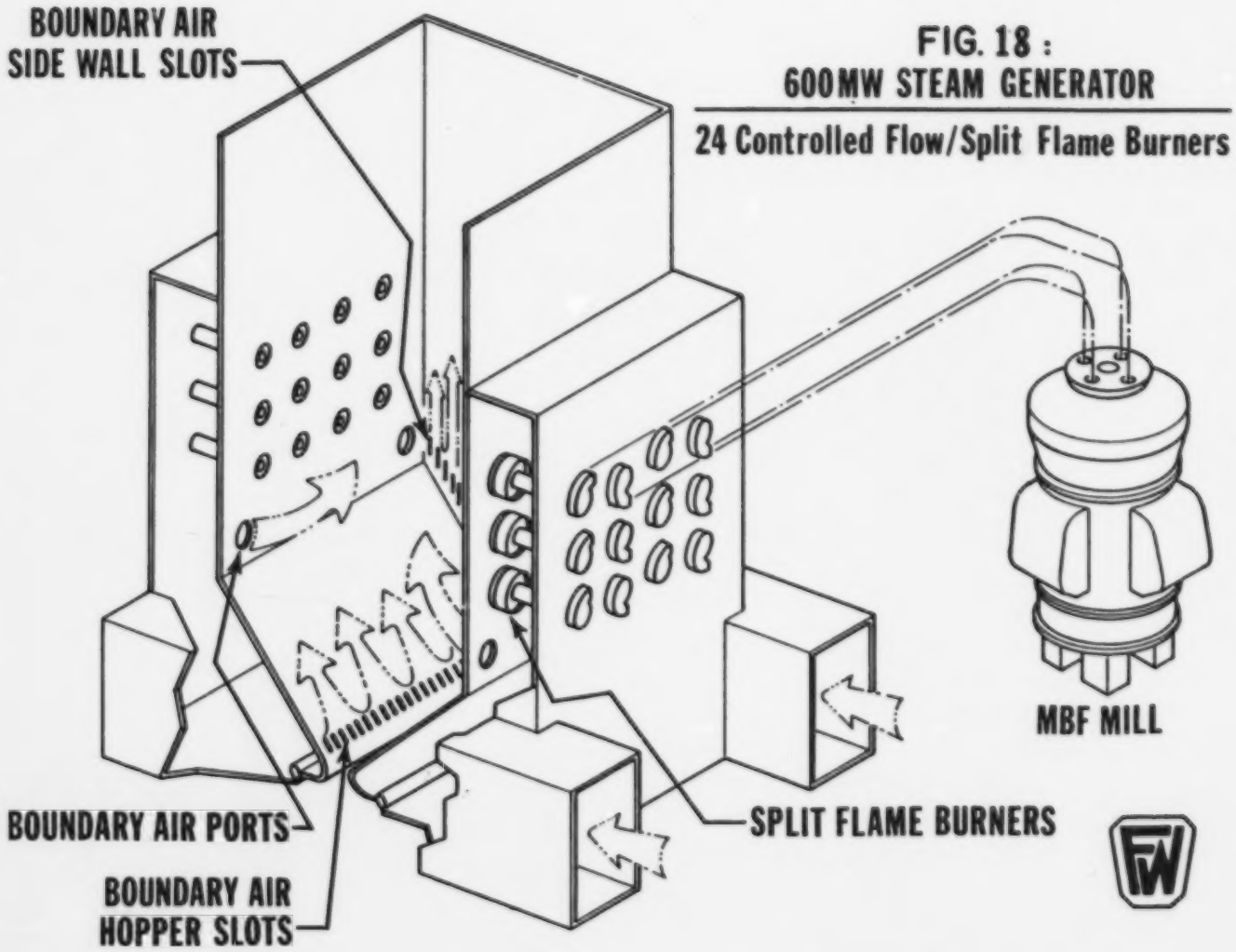


FIG. 18 :
600MW STEAM GENERATOR

24 Controlled Flow/Split Flame Burners

AN EVALUATION OF NO_x EMISSIONS FROM COAL-FIRED STEAM GENERATORS

By:

R. A. Lisauskas and J. J. Marshall
Riley Stoker Corporation
Worcester, Massachusetts 01613

ABSTRACT

The design evolution of the Riley coal-fired TURBO Furnace and Directional Flame Burner is reviewed. Burner aerodynamics are characterized and the effectiveness of burner adjustments and staged combustion in reducing NO_x emissions in this unique firing system are discussed. Field test emissions data are presented and analyzed with respect to burner operating variables. A decrease in NO_x emissions is observed as mixing of fuel and air in the near burner zone is delayed. Further development of directional flame and controlled mixing burners for coal-firing applications is also discussed.

INTRODUCTION

In a continuing effort to characterize the production of NO_x in coal-fired Riley TURBO Furnaces, the Riley Stoker Corporation is obtaining field data on operating units as part of the company's long-term NO_x Program. Since our report at the Second EPRI NO_x Control Technology Seminar, the additional field data collected has been incorporated into the data base from which a regression analysis is performed to aid in the prediction of NO_x emissions from the TURBO Furnace. This model for predicting NO_x was discussed in some detail in previous conferences[1,2] and is only briefly mentioned here.

The additional data collected in the past 2 years includes information on dry bottom TURBO Furnaces with overfired air. A great effort has been placed on trying to quantify the effects of variation and adjustments to the specific types of burner hardware unique to this firing system. This includes components such as velocity control dampers, adjustable secondary air vanes, and coal stream spreaders. Although the Riley TURBO Furnace and its firing system have been detailed in the open literature, a summary review is made here to reacquaint the reader.

The focal point of much of the latest effort has been to characterize the burner aerodynamics which have the greatest effect on controlling the evolution of fuel-bound nitrogen into NO. The aerodynamics of concern are in the near burner zone, described in our previous paper as the primary zone of the overall furnace model. Although the thermal fixation of nitrogen in air contributes significantly to the NO emission, the conversion of fuel-bound nitrogen is the prime contributor to the overall emission of NO in the range of values evaluated here.

TURBO FURNACE DESIGN

Furnace Design Features

The unique configuration of the Riley TURBO Furnace was first used in the late 1940's. At that time, the difficulty concerned the combustion of a petroleum byproduct known as fluidized coke. While this fuel had a high calorific value, it was slow in burning and needed a longer furnace residence time. Bending the front and rear walls inward, but not to the extent of a roof- or arch-fired furnace, provided a cost-effective means of furnishing a longer path for the combustion process compared to a straight wall unit front-, rear- or opposed-fired. As illustrated in Figure 1, the fuel and air admitted through the burners on both walls was inclined to the center of the furnace. Combustion took place as the mixture curled down and then up through the lower furnace.

The venturi shape formed by this tubing arrangement and the diffused flame pattern provided by the Directional Flame Burner produced an even heat distribution across the unit while the walls of the lower and upper furnace remained comparatively free of ash or slag buildup.

Second generation Riley TURBO Furnaces were built primarily for natural gas and residual oil firing as was dictated by the energy climate at that time. The furnace had a flat floor formed by the water wall tubes. With the ability of the burner to vary the direction of the air with respect to the fuel flow, it brought the performance of these widely varying fuels more in line with each other by bringing the furnace exit gas temperature on each fuel closer together than it would be on a straight wall unit. Coal was also burned in these flat bottom or slag tap type furnaces, but this was usually limited to comparatively high slagging characteristic coals. A typical coal-fired wet bottom TURBO Furnace of this type is shown in Figure 2. For other types of coal, Riley still used straight wall-fired units at that time.

During the mid- to late-1960's, many boilers were being built to fire oil and gas. About this same time, Riley began to intensify its research in the area of NO_x emissions. This work occurred into the early 1970's and has been well documented.[3,4,5,6] The work consistently showed that the

baseline emission of NO_x was always lower in the TURBO Furnace than the straight wall-fired units. To meet the modern needs of the industry and the switch of the energy mix back to a coal base, the third generation Riley TURBO Furnace was developed. This modern concept includes a dry hopper bottom with a water-impounded ash receiver below the hopper throat. The critical furnace design dimensions are shown in Figure 3.

A list of some of the Dry Bottom Riley TURBO Furnaces supplied for coal firing is shown in Table I. These units were designed to fire a wide range of coal types ranging from eastern bituminous to western subbituminous. The typical analysis for a few of these coals in shown in Table II. Figures 4 through 9 illustrate the variation of the sectional side elevations for some of the units in Table I. As can be seen in these figures, there are significant differences in each unit design and its equipment for this one type of boiler. These differences are the results of many factors. Some of the more important factors are the coal characteristics such as higher heating value, slagging tendency, grindability, and customer preferences.

Burner Design Features

The Directional Flame Burner (Figure 10) is used exclusively in the Riley TURBO Furnace. This is a unique diffusion-type burner. These are slow mix, nonswirl burners. The secondary air and primary air coal jets are essentially parallel. Adjustments can be made to the directional secondary air vanes to deflect the secondary air into or away from the primary stream. A velocity control damper is provided to allow for varying the secondary air velocity. An adjunct overfire air or staged combustion port is dampered to adjust burner zone stoichiometry. With the combination of these three airflow control systems in the burner, the degree of mixing in the primary flame zone can be controlled over a wide range. A major effort is being made to characterize the effect of these three design features on NO_x production in coal-fired TURBO Furnaces.

Although not adjustable on commercial burners, some modification has been made for test purposes to utilize an adjustable coal spreader. This allows variations of the axial relationship between the primary and

secondary stream while also significantly changing the interaction point of the flames from the front and rear wall burners.

All of these burner adjustment features not only impact NO_x evolution, but can have an important major effect on overall furnace performance. Care must be taken when making burner adjustments that this performance is not adversely compromised. This would include situations such as high CO, excessive carbon loss in the ash, reduced unit efficiency, poor or loss of superheater or reheater temperature control, extreme reducing atmospheres that could cause corrosion or excessive fouling, or a host of other difficulties.

With this in mind, our long-term NO_x control program includes a potential problem analysis in our decision process to ensure that a viable NO_x control scheme is formulated that will incorporate safe and reliable boiler operation with the most efficient utilization of present fuel resources.

FIELD TEST RESULTS

Burner Aerodynamics

As discussed earlier, one of the methods of controlling the fuel and air mixing history in the Directional Flame Burner is through adjustment of the secondary air vanes locate' above and below the coal nozzle (as shown in Figure 10). These directional air vanes can be tilted up or down in a number of different positions to change the rate of fuel/air mixing. A description of these various positions is given in Figure 11.

Burner exit geometrics for four selected vane positions are illustrated in Figure 12 for the fuel nozzle slot. These sketches help to provide a conceptual understanding of the influence of burner vane position on near field fuel/air mixing.

The burner input to the furnace, as shown in Figure 12, can be divided into three streams: the coal plus primary air stream, and secondary air streams above and below the burner nozzle. The slowest mixing occurs for air vane setting characterized as Number 2. Secondary air above the burner nozzle at this setting is introduced essentially parallel with the primary coal air stream while the air entering below the nozzle is directed away

from the primary stream. The degree of mixing between these primary and secondary streams increases progressively for burner vane positions numbered 2, 9, 10, and 7, respectively. Burner vane setting Number 7 produces the earliest intersection of the upper secondary air stream with the primary coal-air stream. In all of the cases shown in Figure 12, the coal spreader is tilted up with respect to the burner centerline. The same order of burner air vane ranking, however, would also exist for a coal spreader designed with a 0° upward tilt.

The results of tests on three dry bottom TURBO Furnaces to determine the effect of burner vane position on NO_x is shown in Figure 13. The results for each unit represent operation at maximum continuous rating and are evaluated for similar firing conditions with the only change being the adjustment of the burner directional air vane position. One of the units is designed without overfire air and is operated on subbituminous coal. The other two units are designed for different levels of staged combustion and each fires bituminous coal.

The mixing concepts described earlier can be used to provide some insight on the trend in the variation of NO_x emissions with burner air vane setting. NO_x levels are observed to increase with the degree of mixing. Highest emission levels occur at air vane position Number 7, while lowest emission levels occur at position Number 2.

The effect of a limited range of coal spreader angles on NO_x emissions is shown in Figure 14. NO_x emissions appear to be the most sensitive to the degree of coal spreader tilt at the higher NO_x producing (i.e., earliest mixing) air vane settings.

Staged Combustion

Field data analyzed to date shows that staging the combustion process by the use of overfire air always has the effect of decreasing NO_x. The percentage reduction can vary a great deal, from as low as 8 percent to as high as 24 percent. All reductions were evaluated under similar firing conditions with the only mechanical change being the shift of overfire air dampers from shut to full open. The large variations in the NO_x percentage reductions are the result of numerous design and operating factors.

The effectiveness of overfire air as a NO_x control technique is dependent, to a degree, on what other control methods are applied. If the NO_x emissions, for example, have already been reduced by some other means with the burner aerodynamics, such as directional vane or coal spreader setting, the effects of overfire air are not as great. This is basically verifying what has been known for some time. NO_x controls are not additive and this is even more prevalent when the baseline NO_x levels are already low.

FUTURE WORK

The current effort of collecting and analyzing field data on emissions and furnace performance will continue into the forseeable future. Many of the units listed in Table I not already online, will be coming online in the next 12 months. The information collected on these new TURBO Furnaces will be included into the data base for this type of boiler. This will aid in refining the regression analysis used to predict emissions and furnace performance. Test series on specific units will be designed to give further quantifications to the effects of the design and adjustment of the various burner hardware.

In the laboratory, the field program will be supplemented by numerous development projects. These will include cold flow model studies into the aerodynamic characteristics of the burners, further development of a lower furnace model, and firing tests in a research furnace. The present Riley research furnace, capable of firing 300 MMBtu/hr on gas or oil, is in the process of being retrofitted to fire solid fuels to a nominal rate of 100 MMBtu/hr. This conversion includes equipment for sizing, storing, and metering the fuel, as well as an air preheater for proper combustion, and a tail-end cleanup system to ensure local emission regulations are adhered to.

Development will be for the directional flame and circular controlled mixing types of burners. Circular burners are being developed in a full range of sizes for application in both utility and industrial units, primarily for retrofit and upgrading purposes.

SUMMARY

The dry bottom Riley TURBO Furnace offers a unique furnace and burner combination that allows flexibility in limiting NO_x release while

maintaining safe and efficient operation consistent with economic use of our indigenous natural resources. The field data has shown that adjustments to the various burner hardware, such as overfire air ports and directional air vanes, can significantly reduce the NO_x emissions. The improved combustion techniques being developed will assist in further reducing pollutant emissions to meet the new environmental regulation that will be more stringent in the future for the full range of boiler sizes in the utility and industrial market.

REFERENCES

1. Rawdon, A. H., Lisauskas, R. A. and Zone, F. J., "Design and Operation of Coal-Fired TURBO Furnaces for NO_x Control," Proceedings: Second NO_x Control Technology Seminar, EPRI FP-1109-SR, July 1979.

2. Lisauskas, R. A., "Design and Operation of Coal-Fired TURBO Furnaces for NO_x Control," Presented to the Committee on Power Generation Association of Edison Illuminating Companies, April 19, 1979.

3. Rawdon, A. H. and Sadowski, R., "An Experimental Correlation of Oxides of Nitrogen From Power Boilers Based on Field Data," Presented at the 93rd Winter Annual Meeting of the American Society of Mechanical Engineers, New York, November 27-30, 1972.

4. Rawdon, A. H. and Johnson, S. A., "Application of NO_x Control Technology to Power Boilers," Proceedings of the American Power Conference, Vol. 35, pp. 828-837, 1973.

5. Rawdon, A. H. and Johnson, S. A., "Control of NO_x Emissions from Power Boilers," Presented at the Annual Meeting of the Institute of Fuel (Australian Membership), Adelaide, Australia, November 1974.

6. Hunt, P. J., "Boiler Design for Reduced Emission of Pollutants," Presented at the Industrial Fuel Conference, Purdue University, West Lafayette, Indiana, October 3, 1974.

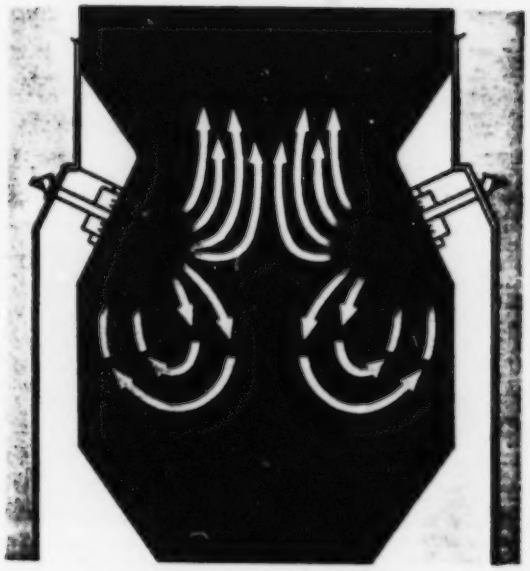


Figure 1. Configuration and flow patterns of the TURBO Furnace.

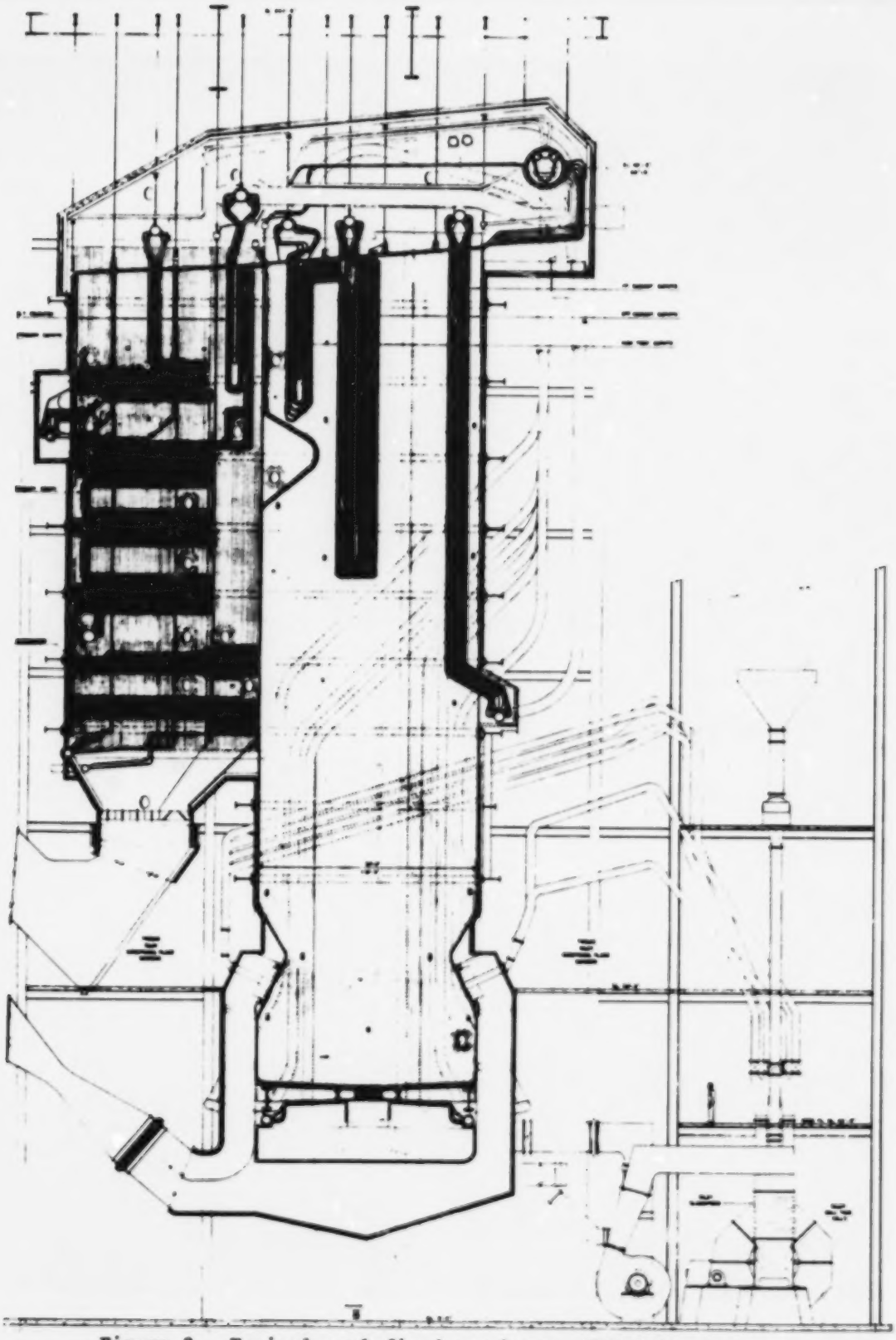


Figure 2. Typical coal-fired wet bottom TURBO Furnace.

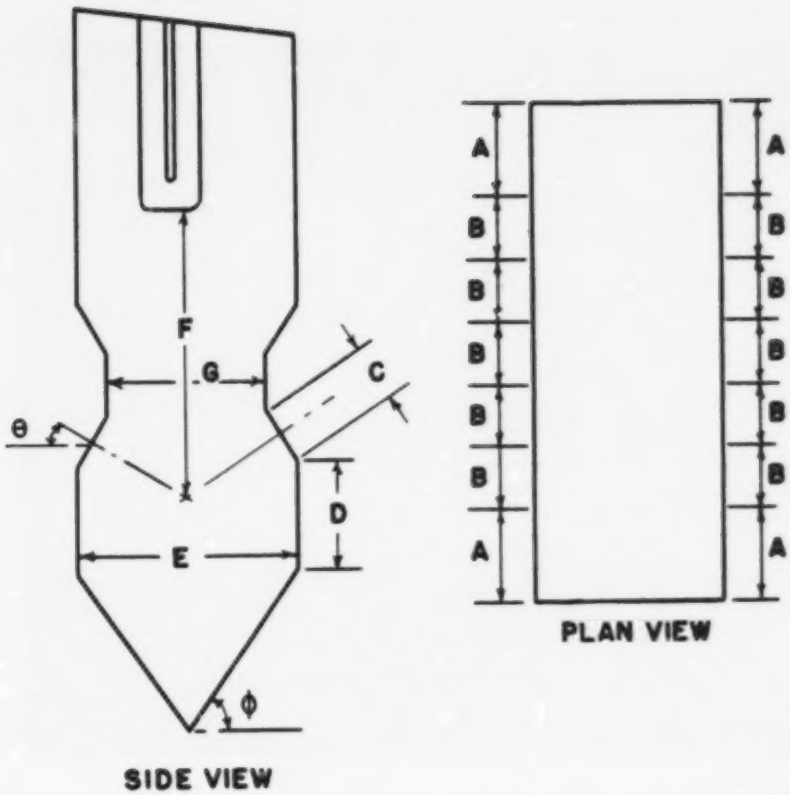


Figure 3. Dry bottom TURBO Furnace critical design parameters.

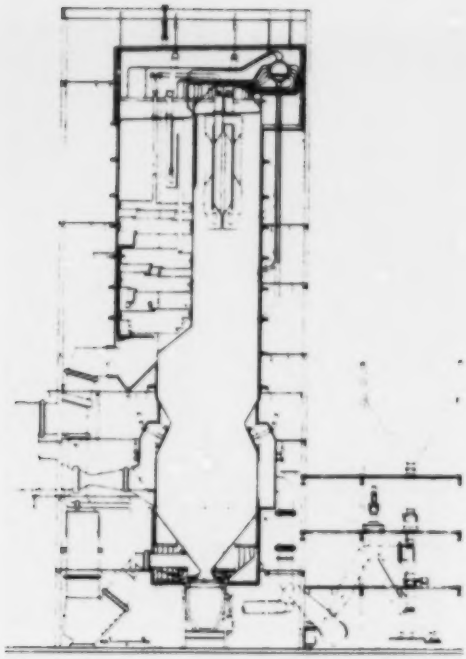


Figure 4. Southwest Power Station City Utilities of Springfield Springfield, Missouri.

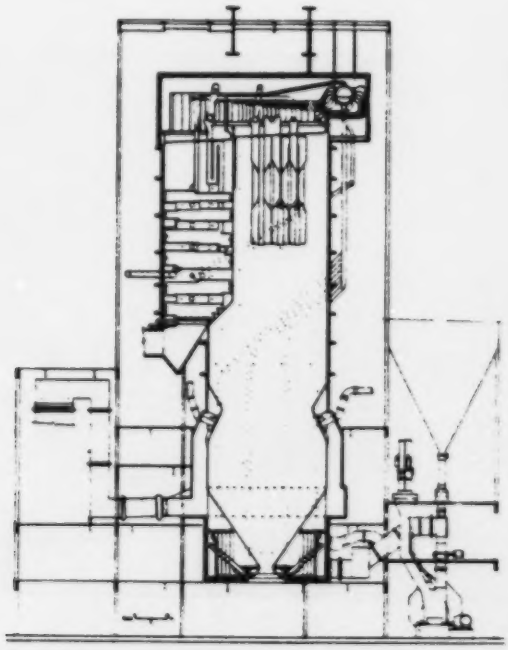


Figure 5. Interstate Power Company Lansing Power Station Lansing, Iowa.

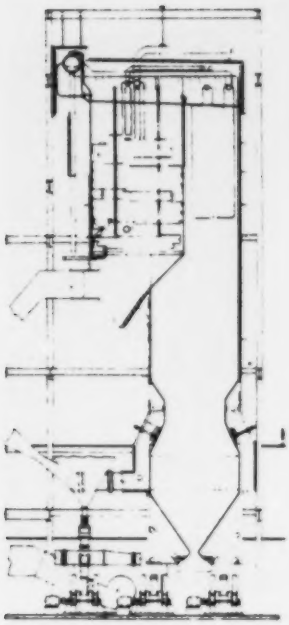


Figure 6. Santee Cooper South Carolina Public Service Authority, Georgetown Steam Electric Station, Unit No. 2, Georgetown, South Carolina.

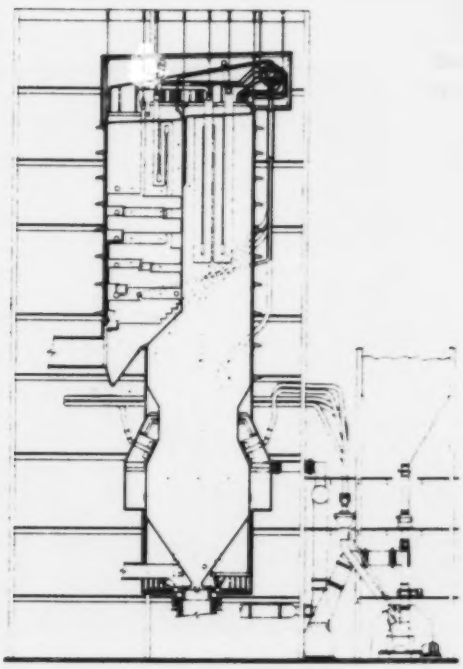


Figure 7. South Mississippi Electric Power Association, Purvis Plant, Units No. 1 and 2 Hattiesburg, Mississippi.

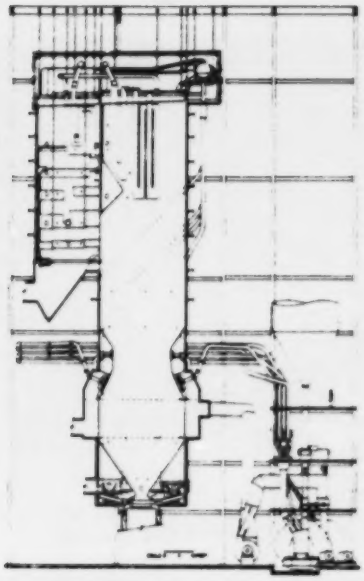


Figure 8. Alabama Electric Cooperative, Inc. Tombigbee Plant, Units No. 2 and 3, (near) Jackson, Alabama.

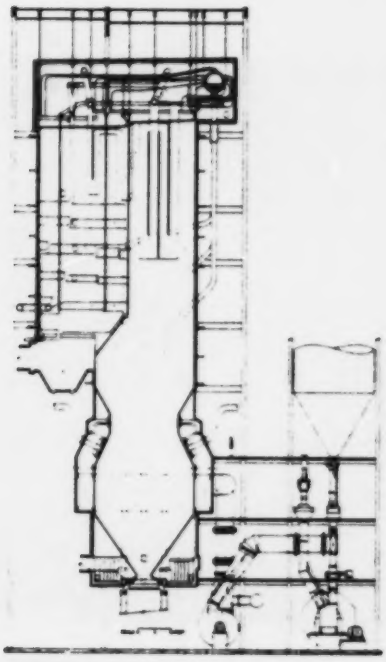


Figure 9. Arizona Electric Power Cooperative, Inc. Apache Station, Units No. 2 and 3, (near) Cochise, Arizona

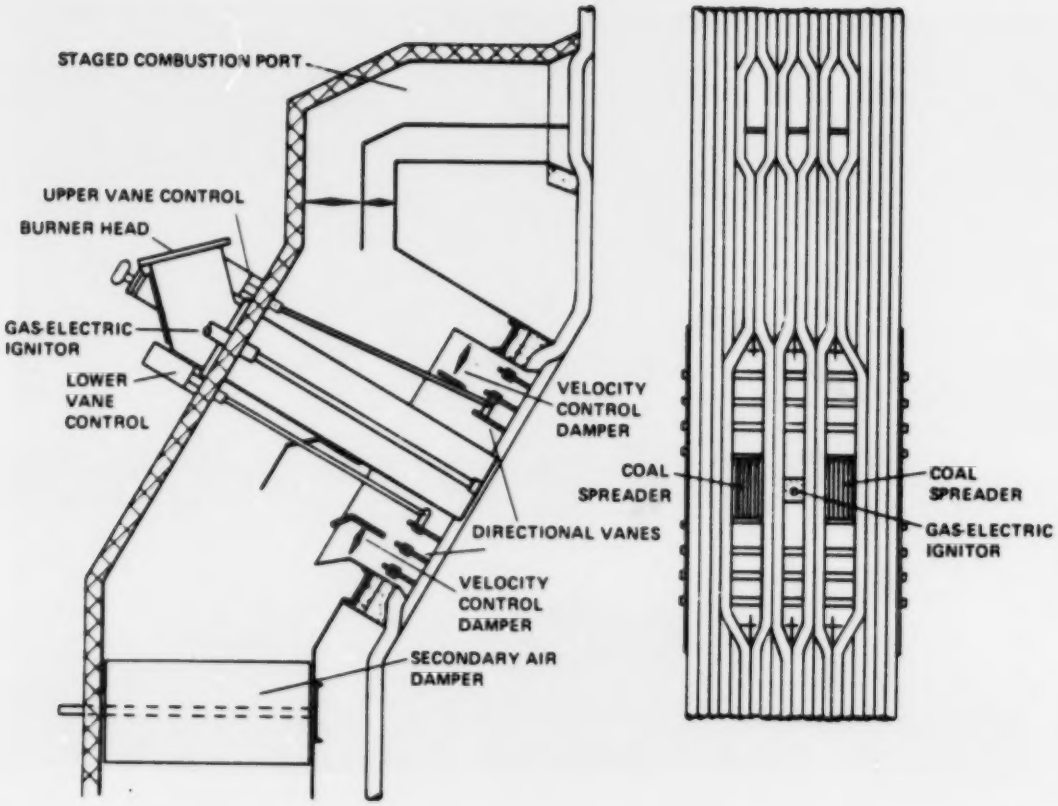


Figure 10. Riley Directional Flame Burner with staged combustion ports for coal firing.

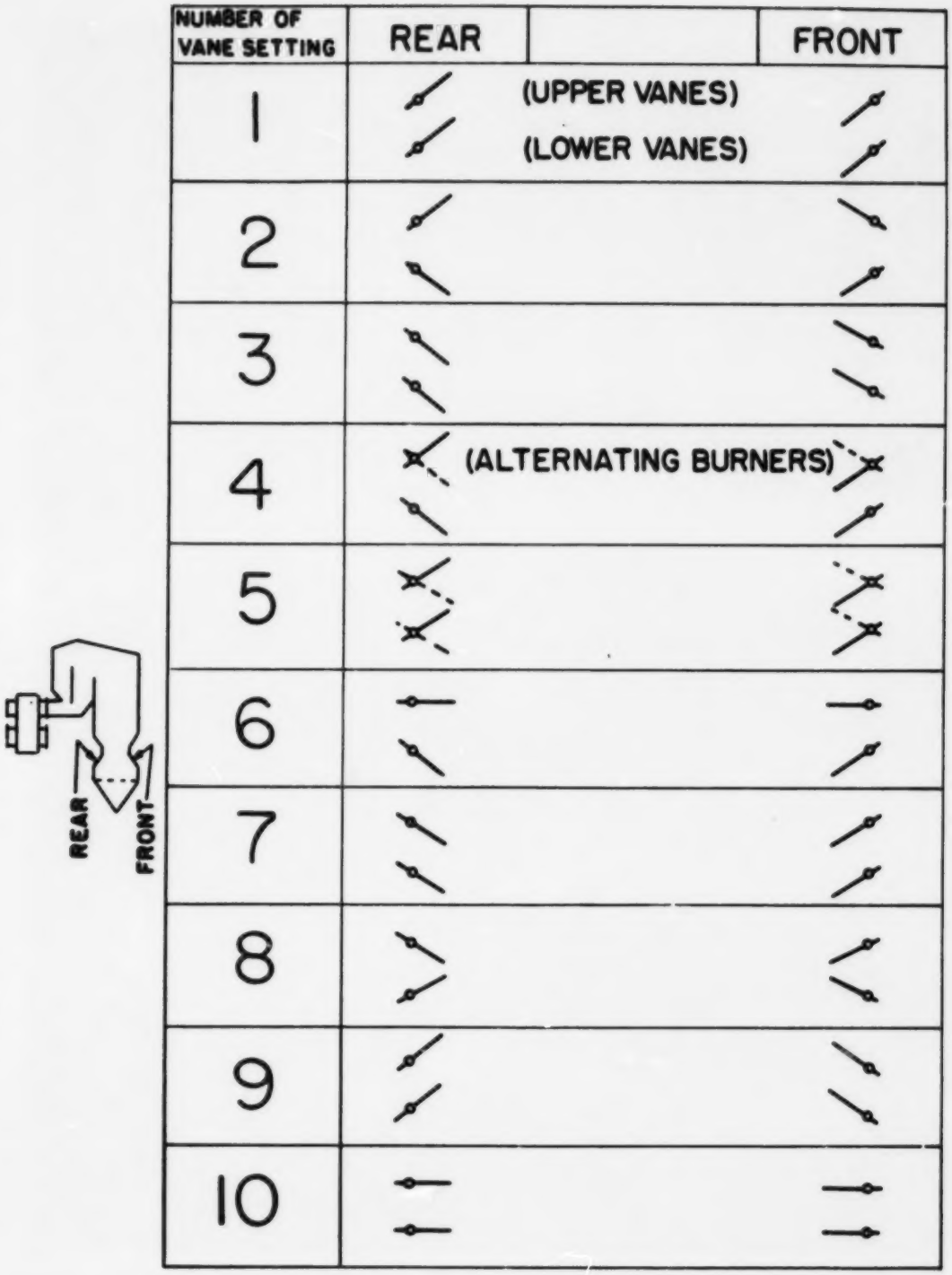


Figure 11. Burner air vane settings.

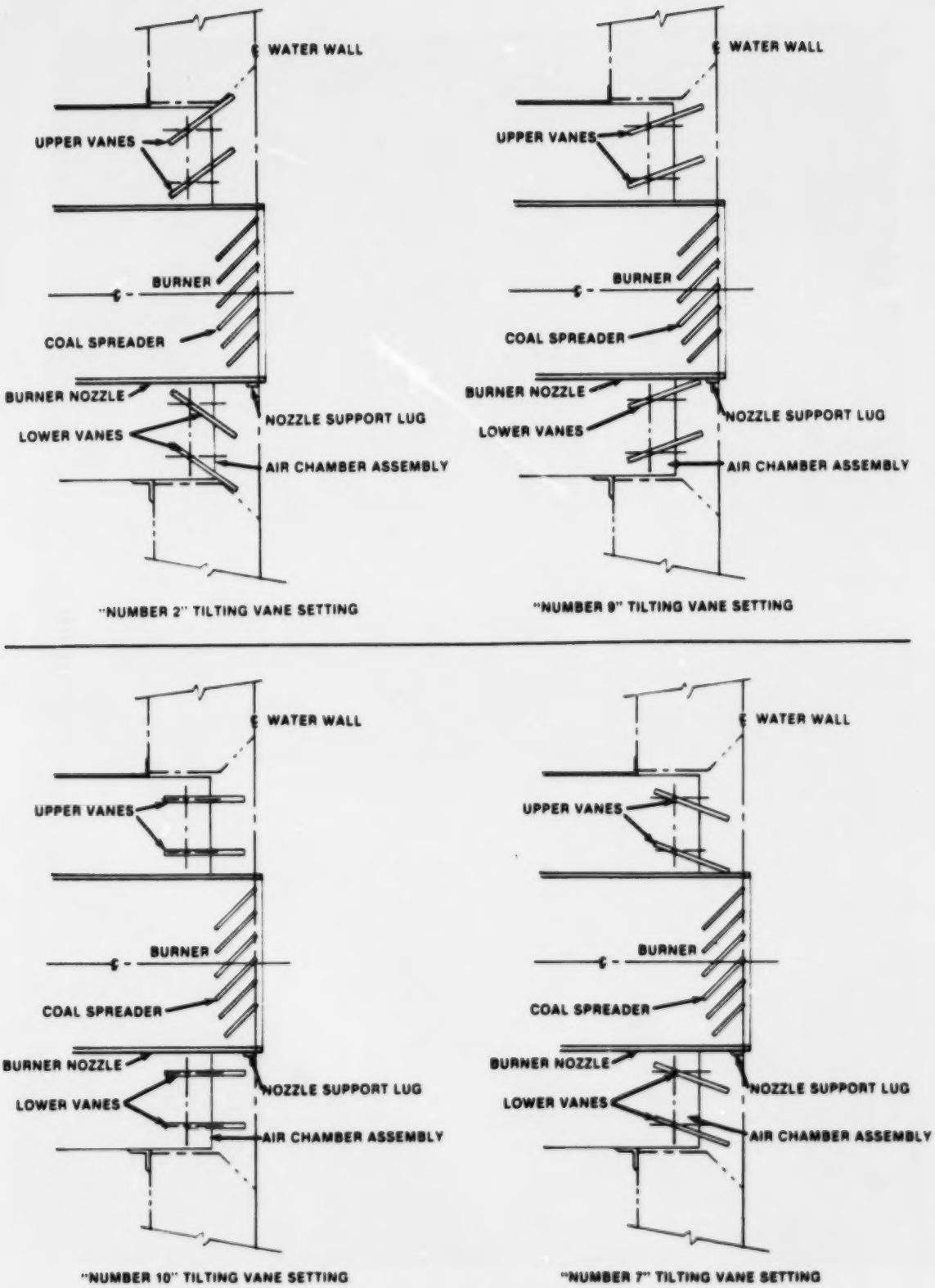


Figure 12. Directional flame burner exit geometries.

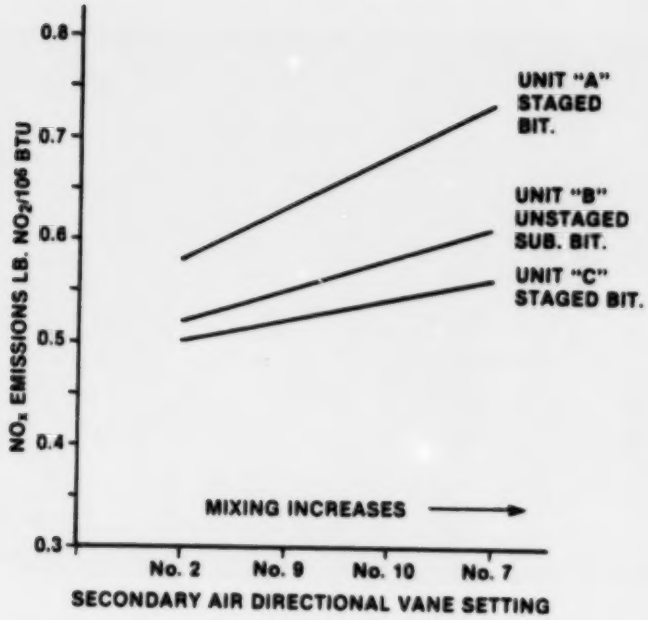


Figure 13. Effect of burner air vane position on NO_x emission.

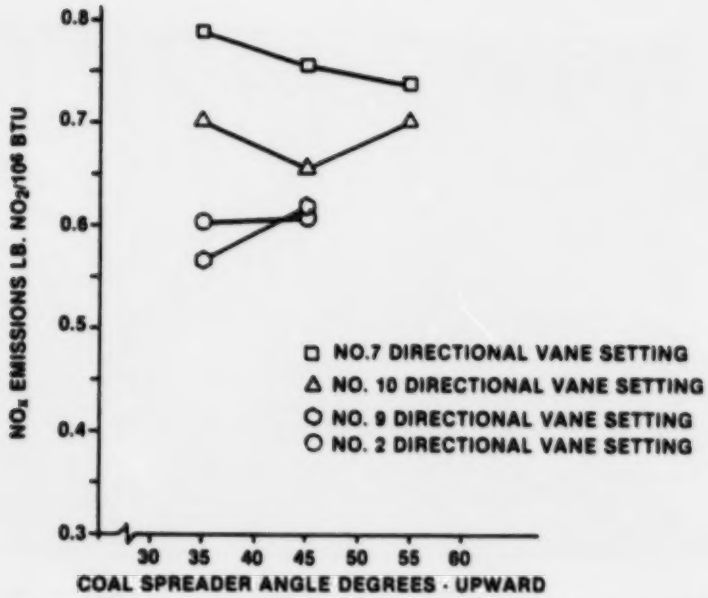


Figure 14. Effect of coal spreader angle on NO_x emission.

TABLE I. RILEY DRY BOTTOM TURBO FURNACE UNITS

Customer	Scheduled Startup Year
Union Carbide	1963
City of Springfield	1976
Emery Industries	1976
Interstate Power Company	1977
Cleveland Cliffs Iron Company	1978
South Mississippi Electric Power Association (two units)	1978
Santee Cooper Public Service Authority	1977
Delmarva Power and Light Company	1980
Dairyland Power Cooperative	1979
Salt River Project	1978
Arizona Electric Power Cooperative, Inc.	1978
City of Kansas City	1980
Alabama Electric Cooperative, Inc.	1978
Wisconsin Electric Power Company	1980
Wisconsin Electric Power Company	1982
Arizona Electric Cooperative, Inc.	1978
Alabama Electric Cooperative, Inc.	1979
Salt River Project	1978
Salt River Project	1984
Cleveland Cliffs Iron Company	1979
Cajun Electric Power Cooperative, Inc.	1979
Cajun Electric Power Cooperative, Inc.	1980
Hoosier Energy Division	1981
Hoosier Energy Division	1982
Santee Cooper Public Service Authority	1980
Santee Cooper Public Service Authority	1981
Central Illinois Light Company	1983

TABLE II. COAL ANALYSIS

Properties	Coal Rank		
	Bituminous	Bituminous	Subbituminous
% C	66.32	66.80	47.81
% H	4.62	4.67	3.43
% N	1.41	1.40	1.05
% O	7.07	4.01	11.13
% S	2.07	3.54	0.42
% Ash	12.71	12.88	6.16
% Moisture	5.8	6.7	30.0
HHV Btu/lb	11,832	12,064	8,253
Ash fusion temperature (I.D.-Oxy)	2,550	2,180	2,120
Slagging index	Low	High/severe	High/severe

FIRESIDE CORROSION AND NO_x EMISSION TESTS ON COAL-FIRED UTILITY BOILERS

By:

E. H. Manny and P. S. Natanson
Exxon Research and Engineering Company
Exxon Engineering Technology Division
Florham Park, New Jersey 07932

ABSTRACT

This paper will describe the status of an EPA-sponsored field study of NO_x emissions from coal-fired utility boilers. Previous reports discussed the effectiveness of combustion modification techniques to significantly reduce NO_x emissions. The simultaneous investigation of side effects (e.g., particulate emissions, boiler slagging, boiler performance) did not identify any significant problems. However, one potential side effect -- fireside corrosion of the boiler waterwalls -- was only partially studied. Fireside corrosion rates obtained via probes (short-term exposure) could not be correlated conclusively with actual furnace tube wastage experience. Therefore, a long-term corrosion test was undertaken to obtain representative furnace tube corrosion rate data. Results of this test, conducted on the 500 MW No. 7 pulverized-coal-fired boiler at the Crist Station of the Gulf Power Company, are presented and discussed. Details and a progress update are also given for ongoing corrosion investigations sponsored by EPA on four large coal-fired utility boilers designed to meet NSPS NO_x emission standards. Information is also included on a field test using additives to suppress slag formation in a 330 MW pulverized-coal-fired utility boiler.

ACKNOWLEDGMENTS

The authors wish to acknowledge the constructive participation of Mr. R. E. Hall, EPA Project Officer, in planning the field test programs and providing coordination with boiler operators and manufacturers. The assistance and cooperation of the General Electric Company personnel in helping the selection of gas turbines for testing is also gratefully acknowledged. The helpful cooperation, participation and advice of Babcock and Wilcox, Combustion Engineering and Foster Wheeler were essential in selecting representative boilers for field testing and conducting the program. The voluntary participation of electric utility boiler operators in making their boilers available is gratefully acknowledged. These boiler operators include the East Kentucky Power Cooperative, Inc., Public Service Electric and Gas Company, Louisville Gas and Electric Company, Houston Lighting and Power Company, Public Service Company of Colorado and the Gulf Power Company. The authors also express their appreciation for the extensive coal analyses services provided by Exxon Research's Coal Analysis Laboratory at Baytown, Texas and to Messrs. A. A. Ubbens and E. C. Winegartner for their contributions and advice on coal related matters. The valuable assistance of Messrs. L. W. Blanken, R. W. Schroeder, W. Petuchovas, and Mrs. M. V. Thompson in performing these field studies is also acknowledged.

SECTION 1

INTRODUCTION

Exxon Research and Engineering Company (ER&E) under contract to EPA has been conducting field studies since 1970 on combustion modification techniques to control NO_x and other pollutant emissions from utility boilers. In early studies significant reductions of NO_x were achieved in gas and oil-fired boilers under EPA Contract No. CPA 70-90 (1) without optimizing the technology. In a follow up investigation, emphasis shifted to the more difficult task of controlling NO_x emissions in pulverized coal-fired boilers and the assessment of potential side effects. Twelve coal-fired boilers were tested under EPA Contract No. 68-02-0227 (2) in cooperation with boiler owner-operators and boiler manufacturers. In this study reductions in NO_x emissions averaging 39 percent (ranging from 12 to 59%) were achieved with no apparent adverse side-effects. In addition to the optimization of NO_x emissions the study included particulate and unburned combustible measurements, furnace corrosion rate probing, determination of boiler efficiency and observations on changes in boiler operability, i.e., slagging, fouling, flame impingement or instability, etc.

In the current program, presently nearing completion, sponsored by EPA (Contract No. 68-02-1415) and partially by the Electric Power Research Institute (EPRI Project No. 200), five coal-fired and 2 coal, mixed-fuel fired boilers were tested in the Phase I program (3) and four coal-fired boilers, two gas turbines and one oil-fired boiler were tested in the Phase II program now reaching its conclusion. The scope of the program was broadened under these contracts to explore the effectiveness of equipment modifications designed for NO_x control, such as boilers constructed with overfire air ports and use of low NO_x emitting improved burner designs. NO_x emissions in the coal-fired boilers tested were reduced by 34% in the Phase I program and by 38% in Phase II. Potential combustion modification adverse side-effects such as,

particulate mass and size distribution, boiler performance and operability, furnace tube corrosion, etc., received increased emphasis and were studied in more detail than previously. Since combustion modifications for NO_x control potentially may cause increased slagging problems in boilers, as a part of this program a series of tests were conducted with promising results using additives to suppress slag formation in a coal-fired boiler.

Furnace tube corrosion, which may be aggravated by low NO_x operation, is a potential major side-effect. Data developed in past programs with corrosion probes, however, could not be conclusively related to actual furnace tube corrosion. The importance of this problem dictated a major effort to specifically address this question. An extensive long-term corrosion study was undertaken to obtain corrosion rates on actual furnace tubes. This program encompassed the use of corrosion probes, exposure of pre-measured furnace tube panels in the furnace and ultrasonic thickness measurement (mapping) of furnace tubes to determine actual corrosion rates.

Under EPA Contract No. 68-02-2696 a major effort is being expended in an on-going program to obtain long-term corrosion data on three additional coal-fired boilers designed to NSPS standards of 0.7 lbs of $NO_x/10^6$ Btu. Two tests are presently in progress. The 3rd is in the active selection stage and will be combined with Combustion Engineering's test of a new firing concept (rich fireball) for tangentially fired boilers. The scope of this program has also been expanded to include level 1 testing, continuous monitoring of pertinent gaseous emissions and extensive pollutant assessment of solid, liquid and gas streams entering or leaving the boilers.

SECTION 2

TEST PROGRAM UPDATE

Details of test program designs, gaseous sampling and analysis, particulate, SO_x, corrosion rate and boiler performance measurements and calculations have been covered in prior reports (1)(2)(3)(4). This report will update work performed under EPA Contract No. 68-02-1415 which was partially sponsored by the Electric Power Research Institute under EPRI Project No. 200. Field tests conducted under this program were carried out in Phases I and II. Five pulverized coal-fired boilers and two mixed-fuel fired (coal/oil, coal/gas) boilers were tested under Phase I, results of which were reported in EPA Report EPA-600/7-78-036a (NTIS No. PB281078)(3). Phase II, covered by this report, will update the program covering field tests on four coal-fired and one oil-fired boiler with special emphasis on the long term corrosion test conducted on Gulf Power Company's No. 7 boiler at their Crist Station.

NITROGEN OXIDE EMISSIONS

Field tests conducted in the Phase I program are summarized in Table 1 for record and comparison purposes. Included in the table are details concerning the boiler manufacturer, the type of firing, kind of fuel burned, numbers of burners, test variables, number of tests run, and emission data for baseline and optimum low NO_x operation on each boiler tested. Referring to Table 1 it may be seen that uncontrolled (baseline) emissions ranged from 341 to 1383 ppm with only four out of the seven boilers tested meeting the New Source Performance Standard (NSPS) of 0.7 lbs of $NO_x/10^6$ Btu. Three of these, Barry No. 2, Navajo No. 2 and Comanche No. 1 were equipped with overfire air ports while the 4th, Gaston No. 1, had been retrofitted with B&W's new low NO_x burners. Also note that application of combustion modification techniques successfully reduced emissions below the new NSPS standard of 0.6 lbs $NO_x/10^6$ Btu in all cases but two (Mercer No. 1 and TVA No. 5) and even TVA No. 5 could meet the original (old) standard. NO_x reductions ranged from 22 to 45%, averaging 34 percent commenserate with reductions achieved in prior programs.

Results of field tests conducted during Phase II of the program are tabulated in Table 2. It may be noted from Table 2 that baseline emissions in the four coal-fired boilers tested, ranging from 533 to 827 ppm, did not meet the original NSPS standard of 0.7 lbs of $NO_x/10^6$ Btu. Under low NO_x firing conditions, however, two boilers (Cooper No. 2 and Comanche No. 1) met the new NSPS standard 0.6 lbs of $NO_x/10^6$ Btu. There is little doubt however that Louisville Gas and Electric Company's Mill Creek, No. 1 boiler could have met both NSPS requirements, but low NO_x firing was not applied to this unit during the additive tests due to a lack of time. Average NO_x reductions were 38% in the coal-fired boilers tested, ranging from 22 to 62 percent. This is consistent with NO_x reductions achieved in Phase I and earlier programs.

Emission reductions obtained in boilers representative of the utility boiler population and on various current design configurations complying with recent low NO_x requirements or guarantees have been discussed and published elsewhere (1, 2, 3, 4). NO_x emission reduction and optimization achieved on the No. 7 horizontally opposed fired Foster Wheeler boiler at Gulf Power Company's, Crist Station, which was selected for long-term corrosion testing, will be presented here to illustrate slightly different applications of combustion techniques.

Crist Station Boiler No. 7 is a horizontally opposed fired, dry bottom, single furnace Foster Wheeler boiler rated at 500 MW capacity. This unit was selected for testing because it is a large, pulverized coal burning unit of modern design. It also appeared to have the necessary operating flexibility and management support so that it was a good candidate for the Phase IV, long-term corrosion test program. The furnace measures 52 feet 5 inches wide and 40 feet in depth. Six pulverizers feed 24 burners arranged in three rows of four burners each in the front and rear walls of the furnace.

The operating variables found to have a statistically significant influence on NO_x emission levels were load, excess air level, and firing patterns. Figure 1, "ppm NO_x vs. % Oxygen in Flue Gas," has been constructed to indicate the most important relationships found in analyzing the test data. The numbers within the symbols indicate the run number while the symbols indicate the various firing patterns tested. The lines drawn on Figure 1 are least squares, linear regression lines for ppm NO_x vs. % oxygen calculated for each firing pattern.

The strong influence of excess air level on NO_x emission levels for all firing patterns is indicated by the steep slopes of the lines drawn on Figure 1. Very close agreement was found in the calculated regression coefficients (change in ppm NO_x for a 1% change in oxygen) for the various firing patterns, i.e., 69, 80, 81, 59, and 76 for firing patterns S_1, S_2, S_3, S_6, and S_7, respectively. Since excess air levels could be reduced by at least 2% to as much as 5% from normal to low excess air operation without violating the 200 ppm CO maximum emission level guideline or increasing stack plume opacity, this represents an important operating variable for NO_x emission control. Thus, NO_x emissions were reduced by 16% in changing from a full load (480-510 MW) baseline operation (4% O_2) of 827 ppm to 696 ppm under low excess air (2.1% O_2) operation.

Reducing load by 62% from the 480 to 510 MW range to 190 MW under normal excess air firing operation resulted in lowering NO_x emissions by about 37%. Staged firing generally resulted in reduced loads as well as reduced NO_x emission levels. Separating the effect of staged firing on NO_x emission levels from the load effect indicate the following. Staged firing operation, S_2, top burners fired lean (by reduced coal flow to top row of burners) and normal excess air (4% O_2) resulted in a 12% reduction in NO_x emissions (827 ppm to 728 ppm) with about 5% due to load reduction (496 to 451 MW average) and the remaining 7% due to staged firing. Staged firing operation, S_3, (1 top mill on air only) resulted in a 39% reduction in NO_x emissions (to 509 ppm from 827 ppm) with about 12% due to load reduction and 27% due to staged firing. Finally, S_6, staged firing with both top mills on air only produced a 72% NO_x emission reduction with about 32% due to reduced load (230 MW vs. 495 MW). Part of the load reduction experienced during the test period, however, was due to abnormal operating difficulties such as partial air heater plugging.

The combined effect of low excess air and staged firing operation resulted in further NO_x emission reductions as would be expected. Thus, the ppm NO_x levels (and % NO_x reduction from the 827 ppm measured under baseline operation) were 451 (-31%), 400 (-52%) and 244 (-70%) for S_2, S_3 and S_6 staged firing patterns, respectively. These results indicate that this boiler has an excellent NO_x reduction capability through modified combustion operation.

PARTICULATE EMISSIONS AND BOILER PERFORMANCE

Low NO_x combustion modification techniques, especially staging the firing pattern in combination with low excess air firing, results in less intense combustion conditions than conventional firing methods. A tendency toward increased burnout problems, therefore, may occur which, potentially, could increase particulate mass loading as a consequence of increased carbon in the fly ash. In addition, these effects could also result in changes in particulate particle size distribution. Changes in particulate mass loading and particle size distribution could adversely affect collection efficiency in electrostatic precipitators or in other collection devices while an increase in unburned combustibles could have a corresponding adverse effect on boiler efficiency. A further potential adverse side effect of low NO_x operation could be a change in fly ash resistivity which might have a similar adverse affect on precipitator collection efficiency. Measurements of resistivity, however, were beyond the scope of this program.

Low NO_x combustion modification effects on dust loading were investigated using an EPA Method 5 type sampling train incorporating a Brink cascade impactor for particle size determination. Measurements of total mass loading and particle size distribution were made under baseline and optimized low NO_x operating conditions upstream of the electrostatic precipitators. In the latter phase of the contract dust loading measurements were made with EPA's SASS train sampling system. Results of the analyses of the latter tests, however, are not available at this writing.

A summary of particulate emissions and particle size distribution determination results for boilers tested in the Phase II program are tabulated in Tables 3, 4, and 5, respectively. Comparing particulate mass loading data in Table 3 for baseline against low NO_x operation, it may be seen that mass emissions under low NO_x firing conditions, for the tests in the Phase II program, are essentially the same as for baseline operation, requiring little or no change in electrostatic precipitator collection efficiency. Referring to Tables 4 and 5 it again may be seen that low NO_x operation has very little, if any, effect on particle size distribution. Aside from potential changes in resistivity, therefore, it may be concluded from these data, as in the

Phase I and prior programs, that there are no significant differences in particulate mass loading or particle size distribution under low NO_x combustion conditions.

Increases in percent carbon on particulate are noted for low NO_x firing conditions in Table 3 which do not seem to have a corresponding direct effect on mass emissions. Furthermore, the expected decrease in boiler efficiency (Table 6) not only failed to materialize but for the low NO_x conditions efficiency, if anything, is even greater by a small margin leading to the conclusion that low NO_x firing has only insignificant effects on boiler performance.

SECTION 3

ANTI-SLAGGING ADDITIVE TESTS

Low NO_x combustion modifications, especially staged firing in combination with low excess air operation, can result in lower net reducing atmospheres in the bottom of the furnace often accompanied by higher temperatures. Under reducing atmospheres, coal ash fusion temperatures generally are about 200°F lower than for oxidizing conditions. This fact, coupled with higher furnace temperatures can affect the character of the slag formations making them more fluid and sticky with potentially greater slagging difficulties. Where boilers may be operating near incipient slagging conditions, the application of NO_x reduction techniques could result in increased slagging problems.

A part of the Phase II program was devoted to investigation of means to control increased slagging if ever this problem should occur when applying NO_x control modifications. The potential use of additives gave promise of being the most cost effective solution to control or ameliorate slagging conditions in coal-fired boilers. Accordingly, arrangements were made with Basic Chemicals and the Louisville Gas and Electric Company to conduct Cooperative tests on LG&E's No. 1 boiler at the Mill Creek Station. Rated output of the No. 1 boiler is 325 MW but LG&E had arbitrarily derated the unit to 300 MW in order to keep slagging conditions within mangeable bounds.

A series of eight tests were run during June, 1979; four without additive injection to develop "baseline" operating information and four while injecting Basic Chemicals UltraMag additive, an ultra fine (<2 microns) dispersion of MgO in heating oil. Additive was injected at three different rates at each of the four corners of the furnace at the B and C slag blower elevations immediately above the top burners. Boiler loads of 325-330 MW were maintained during the tests, sufficient to promote slagging, and the effectiveness of the

additive was judged by the length of time that load could be maintained at this level before operating parameters became critical, forcing a cut-back in load.

Results of the anti-slagging additive trials are summarized in Table 7. Referring to Table 7, it may be seen that tests 200, 201, and 203 (baseline - no additive) achieved 12 hours operation at full load, rated conditions (325-330 MW) before superheat and reheat steam temperatures bordered on uncontrollability. Note test 202 (no additive). However, where the boiler was slagged to the point of being out of control in 4 1/2 hours; a very short period. The reasons for this drastic performance were not readily apparent but may possibly be attributed to the fact that furnace clean-up prior to the test may not have been as effective as before or that a change to a higher slagging coal may have occurred for that day.

In tests 204 and 205 additive was injected continuously at the rate of 15 GPH. Referring to Table 7 it may be observed that full load capability of the boiler could be maintained under these conditions for a period of 15 and 17 hours, respectively, or an additional 3 and 5 hours longer than without additive injection. These results testify to the technical feasibility and effectiveness of the use of additives at low injection rates with pulverized coal firing. Other potential benefits, which were beyond the scope of these investigations, may also acrue from additive usage, such as, easier clean-up of the boiler during nightly reduced load periods. For example, it may not be necessary to reduce load as much and the clean-up period possibly may be shortened to achieve the same degree of cleanliness. Load carrying capabilities, which are of special importance in tight load demand situations, therefore could be improved.

Tests 206 and 207 were run in an attempt to optimize the additive injection rate and to test the effectiveness of other injection methods. Neither results, however, were quite as effective as injecting the additive continuously at the rate of 15 GPH.

It is concluded from these tests that anti-slagging additives may be effective in controlling or ameliorating slagging problems in pulverized coal fired utility boilers especially when "low NO_x" combustion modifications

may be employed. The degree of slag reduction, the benefits of increased load carrying capability, the optimum rate and the most effective injection method, however, need to be defined in more extensive testing to shed more light on the economics and technical feasibility of additive usage for this purpose.

SECTION 4

CRIST NO. 7

LONG-TERM FURNACE TUBE CORROSION INVESTIGATIONS

Furnace tubes in pulverized coal-fired boilers corrode under oxidizing atmospheres due to the corrosive effect of iron alkali sulfate attack. Under reducing conditions, which may occur as a result of combustion modifications for NO_x emission control, furnace tube corrosion may be accelerated, particularly when high sulfur, high iron content coal is fired, due to intergranular penetration of the tube surfaces by iron sulfide.

Earlier investigations of this potential side effect employed corrosion probes under accelerated conditions to develop corrosion rate data. Average coupon corrosion rates obtained in these programs were approximately 50 mils/year with considerable scatter between high and low values. Subsequent investigations conducted under decelerated conditions approximating the actual tube environment, reduced this average to around 19 mils/year with less scatter in the range of the data. Corrosion rates obtained via probes, however, are still an order of magnitude higher than the 1 to 3 mil/year corrosion normally experienced in boiler furnace tubes.

Since corrosion data developed by probes could not be handily related to actual tube corrosion experience and this question is of major importance to the NO_x emission control program, a special long-term corrosion field study was undertaken. These studies were conducted on Gulf Power Company's, Crist Station, No. 7 boiler with the participation and cooperation of Foster Wheeler Energy Corporation. The major purpose of this long-term study was to obtain quantitative measurements of furnace tube fireside corrosion rates under both baseline and staged combustion operation. Three corrosion measurement techniques were used: (1) corrosion probes, (2) ultrasonic furnace tube wall thickness measurements and (3) replaceable wall tube test sections.

CORROSION PROBE INVESTIGATIONS

Corrosion probes provide a relatively simple, quick and economical means for determining corrosion rates. Even though corrosion rate data developed in these and previous programs could not readily be related to actual furnace tube experience, this type of measurement was continued in the long-term corrosion investigations with the objective of eventual correlation with rates developed by ultrasonic measurement of actual furnace tubes and from exposure of furnace tube test panels.

Corrosion probe testing on the No. 7 boiler at Gulf Power Company's Crist Station was amplified extensively in order to obtain more data and information on the effect of corrosion with time. Conditions of exposure were maintained the same as in prior testing simulating actual furnace tube environment but exposure, rather than at 300 hours only, was varied to include 30 and up to 1000 hours under both baseline and low NO_x conditions to determine initial, intermediate, and longer term corrosion effects. In addition, special ports were installed in the furnace for the installation of the probes in the most desirable areas. Two of these ports were located in the middle of the sidewalls within the burner zone (elevation 129.8 ft.) in the most corrosion prone area and two others were located at the middle of the sidewalls but in the upper furnace area (elevation 157.8 ft.) outside of the expected corrosion area, in order to provide "control" data.

A comparison of corrosion rate data developed in this program on Gulf Power Company's No. 7 boiler at the Crist Station is best illustrated in Figure 2 showing a plot of corrosion rate vs. exposure time for probes exposed to both baseline and low NO_x firing conditions. Referring to Figure 2 it may be noted that coupon corrosion rates decrease with exposure time asymtotically up to 1000-hour exposure. Initial corrosion rates developed at 24 to 30-hours exposure are high with considerable scatter in the data. At 250 to 300 hours exposure, corrosion rates are much lower and more consistent in range. Above 450 to 500 hours exposure, corrosion rates level out to an average rate of 10 to 12 mils/year with very little scatter in the range of the data. These rates, however, are still much higher than the 1 to 3 mil/year wastage expected in actual furnace wall tubes.

It is concluded from these corrosion probe investigations that:

- There are no major differences in corrosion rates for process exposed to low NO_x vs. baseline firing conditions, especially for exposure exceeding 450 hours.
- Corrosion rates developed via corrosion probes decrease with exposure time through 1000 hours approaching an asymtote above 450 hours exposure.
- Corrosion probes exposed for short terms (up to 30 hours) within the burner areas in the furnace sidewalls experience significantly greater corrosion rates than probes exposed outside the burner levels under low NO_x firing conditions. A similar trend is indicated for baseline operating conditions but more data is needed to reach firm conclusions.
- Probes exposed for periods of 300 to 1000 hours experienced no significant differences in corrosion rates due to furnace location (burner vs. nonburner area) or furnace operating mode (baseline vs. low NO_x firing).
- Effective correlation of actual long-term furnace tube corrosion rates require corrosion probe exposure of a minimum of 450 hour exposure.

CORROSION TEST PANELS

In planning the long-term corrosion program discussions with the major boiler manufacturers indicated that the most definitive assessment of furnace tube corrosion would be obtained through use of test panels (premeasured and metallurgically characterized) installed as integral sections of the furnace water tube walls. Since boiler walls are very large and vulnerable corrosion areas are difficult to define in advance of exposure, it was decided to concentrate the panels used in the test on the Crist No. 7 boiler mostly on one furnace wall.

Figure 3 presents a schematic side elevation of the Crist No. 7 boiler showing the location of the furnace test panels. Note that panels 1 and 2 were located below the bottom burner centerline (at 93' elevation) while panels 7 and 8 were installed far above the top burners (elevation 157'-8") with panel 8 located in the right hand sidewall only. These locations were felt to be in areas of relatively low corrosion since both temperatures and depth of slag deposit would be lower than in the burner area where panels 3, 4, 5 and 6 were located. It was also felt that panels 2 and 5 could be affected by curtain air at the rear of the furnace and might experience less corrosion than panels 1 and 3 located in areas without curtain air.

The test panels were fabricated five tubes wide and about 5 feet long. Tubes 1, 3 and 5 were made of SA 210 grade T1 ASTM specification steel while tubes 2 and 4 were made from SA-213 grade T-2 ASTM specification steel. Tube wall thickness measurements were made ultrasonically at three inch intervals (hot side) and six inch intervals (cold side) prior to insertion into Crist No. 7 furnace and after removal from the furnace. Two tubes were removed for each test panel during the November, 1977 boiler overhaul period and replaced with premeasured ASTM specification SA 210 grade T1 steel tubes which is the same material specified for the original wall tubes on Crist No. 7. Ultrasonic tube wall thickness measurements were also made in the field during October, 1976 following the baseline operating period. After removal from the furnace, tubes in the test panels were cleaned, ultrasonically measured by Foster Wheeler, sectioned for photomicrographic examination and corrosion determination.

Based on load demand considerations on the boiler, original test plans provided for a 5-month sustained baseline operating test run starting in May, 1976 followed by a 6-month "low NO_x" operating period with ultrasonic furnace tube thickness measurements at the beginning and end of the baseline operation and middle and end of the "low NO_x" operating period. The prime reasons for including a baseline operating period was the desirability to include "control" measurements and to allow full load operation of the boiler during the summer peak loads. In the period of October, 1976 through January, 1977, a number of operating problems (including pulverizer overhauls furnace tube failures, excessive cold weather, etc.) delayed the start of sustained

"Low NO_x" operation until February, 1977. Subsequently, it was mutually agreed to extend the "low-NO_x" operation until the normal spring outage in 1978, since the unit came off line in July 1977 due to a generator problem. The final low NO_x operating period turned out to comprise a total of 12 months.

Table 8 summarizes the results of the statistical analysis of the furnace test panel measurements. Columns 1 and 2 present test panel measurement data for exposure during 5 months baseline operation and 12 months "low NO_x" operation. Column 3 presents data for the two replacement tubes which were exposed during the last 4 months of the "low NO_x" operating period and columns 4 and 5 present the 13 and 17 month mixed operation data. To facilitate comparisons of different length operating periods, the average change in furnace tube wall thickness is shown in mils per year as well as mils.

The results of statistical analysis of Table 8 can be summarized as follows:

(1) The average loss in furnace tube (hot side) wall thickness during the 5 month baseline operation was about 2 mils (or 5 mils per year) except for panel number 5 which experienced about double that loss. Panels in the non-burner area experienced about the same loss as panels located in the burner area (except panel number 5).

(2) The average loss in furnace tube (hot side) wall thickness was about 5 mils (or 5 mils per year) during the 12 month "low NO_x" operating period. However, the test panels located in the burner area experienced a significantly higher loss level (10 mils per year) than the panels located within the non-burner area (+0.2 mils per year).

(3) Comparing the corrosion rates (mils per year) for the 5 month baseline and 12 month "low NO_x" operating periods revealed:

(a) panels in the non-burner area experienced significantly less corrosion during "low NO_x" operation than during baseline operation (+0.2 vs. -5.3 mils per year). No explanation could be found for this result.

(b) the test panels within the burner elevation experienced significantly greater corrosion during the "low NO_x" operating period than during the baseline operating period (10.4 vs. 6.2 mils/year).

(4) Measurements on the replacement tubes, exposed for the last four months of "low-NO_x" operation, showed no metal loss and the small gain shown must be due to measurement bias or miscalibration.

(5) Columns (4) and (5) of Table 8 containing measurement data representing both baseline and "low-NOx" operation lead to similar conclusions as in (2) above for "low-NO_x" operation. Table 9, below, has been constructed to make this comparison more meaningful. The 17 month "mixed" operation data has been used to estimate 12 month "low-NO_x" operation measurements by deducting the 5 month baseline operation data measured in the field. The estimated 12 month "low-NO_x" operation data is very similar to the actual field measured 12 month "low NO_x" operation measurements and statistical analysis using the estimated results lead to the same conclusions as use of the field measurement data.

The data in Table 8 in columns 4 and 5 are also illustrated in Figure 3 in a more readily understood form. Average changes in tube thickness (hot side) are shown for each of the panels for the 13 month and 17 month mixed (baseline and "low NO_x") operations. As seen earlier, relatively low corrosion rates were experienced on panels 1, 2, 7 and 8 located at some distance from the burners. Panel 5 experienced considerably less corrosion than panels 3, 4 and 6 located within the burner elevation. The existence of rear curtain air might explain this difference.

In summary, the following conclusions can be stated for the analysis of corrosion data from test panels exposed to furnace conditions as Crist No. 7 Unit.

(1) Corrosion rates of furnace tube panels are generally similar at different sidewall furnace locations (below, within and above the burner elevations) when exposed to baseline operation. The average corrosion rate is about 5 mils per year during the first 5 months of exposure. (95% confidence limits are 3.8 to 6.2 mils/year.)

(2) Corrosion rates of furnace tube panels, within the burner elevations are about 10 mils/year while tubes at least 20 feet above or below the burner show little or no corrosion during "low NO_x" operation.

ULTRASONIC FURNACE TUBE THICKNESS MEASUREMENTS

Another method to obtain corrosion rate data is to measure the tubes ultrasonically before and after the desired exposure period, using the difference in thickness measurements to calculate the corrosion rate. Ultrasonic thickness "mapping" of the furnace tubes was employed in the long-term corrosion investigations on Gulf Power Company's Crist Station, No. 7 boiler. Extensive time and effort were expended in planning the tube mapping program to assure reliable measurements. Major considerations involved in determining how, where and how many measurements should be made included the following:

1. Location of most likely and least likely corrosion areas within each wall.
2. Precision and accuracy of the ultrasonic measuring instruments.
3. Changes in normal corrosion rates due to necessary tube cleaning before measurement (possible bias).
4. Additional measurements for quality control purposes.
5. Costs of cleaning tubes, ultrasonic measurement and necessary supervision.

Operating experience indicated that the middle area of boiler side walls, within and just above the top row of burners, is most likely to experience the highest rate of tube wastage. Consequently, four of the six ultrasonic measurement levels were located at the center of the three burner elevations and about 8 1/2 feet above the centerline of the top burner level. The "control" levels were 13 feet below the centerline of the bottom burners and 28 feet above the top burner level. Measurements were more highly concentrated within the middle of the side wall burner area than near the furnace corners or below and above the burner elevation.

Sandblasting or wire brushing necessary to clean the tubes prior to measurement may remove a protecting coating and result in increased wastage. Elaborate precautions were taken to avoid this possible bias through a program of random cleaning and measurement. Pains were also taken to assure that only sufficient sandblasting was done to clean the tubes without metal removal. In addition, special precautions were taken to ensure that measurements were made

at precise elevations on the tubes by welding nuts on the web between tubes in the corners at the given elevations and snapping chalk lines each time prior to measurement.

Statistical Analysis of Ultrasonic Data

To assess the statistical significance of the average tube wall thickness change, the most appropriate "error term" is calculated from the differences between level averages within burner walls. Instrument calibrations were not made more frequently than once per level measured. The levels were far enough apart to expect different corrosion rates and the spots to be measured were determined at each level independently.

This approach does not bias the analysis if calibration errors are insignificant. Comparisons between level means provide a proper error time. The only loss, if calibration variance is negligible, is a slight loss of sensitivity due to a reduced number of degrees of freedom. However, experience has shown that calibration variance appears to be far from negligible.

Table 10 contains a summary of the furnace wall tube (hot side) metal thickness changes (mils/year) for the baseline operation (5 months) and low NO_x operation (12 month duration). The 5 month baseline operation data has been converted to a mils/year basis for ready comparison with the 12 month "low-NO_x" operation data. The body of the table presents the average thickness change for each of the six measurement levels of each furnace wall. The averages have been calculated from all of the paired data (before and after measurements) available for each level after screening out obvious outlier data (20 out of 974 differences). The weighted averages ($\bar{X}$), number of differences (n) and pooled standard deviation(s) are shown for half-walls (burner and nonburner areas), walls and the whole furnace for both the baseline and low NO_x operating periods. Individual wall level averages vary from a high loss of -8.26 mils (left wall, middle burner level under low NO_x operation) to a gain of 0.81 mils (right wall, level 1 at 27 feet above top burners under low NO_x operation). These data were also analyzed by Shewhart Control Charts and 95% confidence limits were calculated by classical and successive difference methods.

The furnace average tube wall thickness loss during low NO_x operation was 3.43 mils. However, two of the half-wall averages were outside of the 97.3% probability control limits; left wall, burner area (-6.24 mils) and right wall nonburner area (+0.36 mils). In addition, the right side wall, burner area average of -5.29 mils is outside of the lower limit of -5.10 mils.

Conclusions from these data and the control chart analysis are:

- The variation of measurement level averages within half-walls is uniform within half-walls during both baseline and low NO_x operation and equals about 1.5 mils.
- With the possible exception of the right sidewall nonburner average, all of the half-wall averages during the baseline operation are about equal after allowing for random level to level variation.
- The low NO_x operation produced significantly high metal loss within the left wall burner area and possibly, significantly high metal loss within the right wall burner area. The right nonburner area showed significantly less metal loss than the furnace average.

Comparison of Baseline and Low NO_x Data

Table 11 presents a comparison of five month baseline and 12 month low NO_x furnace tube wall thickness loss data. Column 1 lists the nonburner and burner average loss for each furnace wall (mils, mils per year and mils per $\sqrt{\text{year}}$) for the 12 month low NO_x operating period. For comparison purposes, columns 2, 3 and 4 list the corresponding loss data for the 5 month baseline operating period in mils, mils per year and mils per $\sqrt{\text{year}}$, respectively. Since the right wall, nonburner area results are so much different from the rest of the data (see Table 11, the nonburner grand average has been calculated with and without the right wall results. 95% confidence limits for the low NO_x operation nonburner (less right wall) and burner grand averages are also shown in Table 11.

The baseline and low NO_x loss data for both nonburner and burner furnace area can be compared on three different bases: mils, mils per year and mils per year. Other bases could be used out these three seem adequate considering

the state of present knowledge of coal-fired, furnace tube corrosion. Since the comparison using mil loss data is obviously biased in favor of the baseline operation (because of the difference in exposure times), no importance can be attached to its statistically significant difference. Omitting the right wall, nonburner area averages, all 7 of the half wall low NO_x averages produced larger metal losses than the corresponding baseline averages calculated as mils.

However, both the mils per year (equal loss per unit of time) and mils per $\sqrt{\text{year}}$ (decreasing rate of loss with time) can provide valid comparisons. On a mil per year basis, four of the seven half-wall comparisons produced lower baseline loss than low NO_x loss and the overall average difference is not statistically significant. However, it should be noted that noted that the baseline operation average of 4.0 mil/year loss for the overall burner area is outside of the 95% confidence limits for the low NO_x burner area (-6.0 to -4.1 mils/year).

If it is believed that the corrosion rate decreases with time (most boiler corrosion coupon data support this concept) and a mils/$\sqrt{\text{year}}$ model is used, then the low NO_x operating period corrosion loss is statistically significantly higher than the baseline operation loss. Six of the 7 half wall differences produce a higher loss during low NO_x operation than the corresponding loss during baseline operation. However, separating the nonburner area from the burner area, it is found that the average difference (-3.05 less -2.12 = -0.93) for the nonburner area is not statistically significant while for the burner area the average difference (-5.05 less -2.58 = -2.47) is statistically significant at the 5% probability level. Thus, it is concluded that the low NO_x operation produces significantly higher corrosion than baseline operation within the burner area.

Figure 4 presents a visual comparison of 5 month baseline and 12 month low NO_x data for average tube wall thickness loss of nonburner area (omitting right wall) and burner area. The projected baseline data on a mils per year basis are shown as dashed lines on Figure 4. The 12-month projected nonburner area value of-3.30 mil loss is very close to the actual

-3.05 mil loss experienced during the low NO_x operating period. However, the projected baseline operation, burner area corrosion loss of 4.00 mils is less than the actual low NO_x operation loss of 5.05 mils. This latter difference is not statistically significant when allowance is made for the uncertainty of both of these loss averages. Note, however, that the 12 month projected baseline operation loss of 2.58 mils for the mil per year model is statistically significantly less than the 5.05 mils per $\sqrt{\text{year}}$ loss during the low NO_x operation. Thus, the conclusion reached depends upon which model is accepted.

Summary of Corrosion Measurements

Major results developed in the long-term corrosion investigations conducted on Gulf Power Company's, Crist Station, No. 7 pulverized coal-fired boiler using corrosion probes, furnace tube panels, and ultrasonic measurement of both the panels and furnace tubes have been discussed and summarized in the foregoing sections. Table 12, which is self explanatory, provides an encapsulated summary of the overall results of the three methods used in these long-term corrosion tests.

SECTION 5

CORROSION TESTING OF UTILITY BOILER COMBUSTION MODIFICATIONS

The influence of NO_x combustion modifications on fireside corrosion, slagging, particulate emissions, boiler performance and other potential side effects has been assessed in prior EPA sponsored studies by Exxon Research and others. As indicated above these adverse side effects, with the possible exception of fireside furnace tube corrosion, have either been proven to be nonexistent or of negligible magnitude at the levels of NO_x control practiced in these investigations. Corrosion assessment studies, however, for the most part, utilized corrosion probes which, in general, provided only a qualitative estimate of furnace tube wastage rates. These studies, normally, were of relatively short duration under "low NO_x" operating conditions; typically two weeks.

EPA recognized very quickly the critical importance of this matter to the NO_x program and the necessity to obtain definitive data and a resolution to this question. As a result, Exxon Research under contract to EPA (3)(4) was directed to undertake the first long-term corrosion investigation, discussed above, on the pre-NSPS No. 7 boiler at Gulf Power Company's Crist Station, in Pensacola, Florida. During the course of this investigation it became apparent that more long-term corrosion data would be required to address the same question on boilers of various designs which were being supplied at that time by the boiler manufacturers to comply with the old NO_x standard of 0.7 lbs $NO_x/10^6$ Btu. Subsequently, a new EPA contract (Contract No. 68-02-2696) was awarded to Exxon Research to conduct long-term corrosion tests on four NSPS designed boilers.

The scope of the new contract was described at the "Third Stationary Source Combustion Symposium" in San Francisco in March 1979. Investigation of furnace tube corrosion essentially is the same as employed on the Crist, No. 7 boiler, i.e., a three pronged approach using corrosion probes, furnace

tube panels, and ultrasonic thickness measurement of furnace tubes and test panels to develop corrosion rate information as described earlier. However, the scope of the new contract is much more extensive including level 1 pollutant assessment tests involving all pertinent solid, liquid and gas streams entering or leaving the boiler and 30 day continuous monitoring of NO/NO_2, CO and O_2 levels, according to EPA guidelines, with frequent reference method checks.

PRESENT STATUS AND PLANS

Original contractual requirements calling for testing of four boilers, one each of the major boiler manufacturers designs, has been changed to more extensive testing of 3 NSPS designed boilers. Two tests have been in progress for the past year and a half in cooperation with the respective utility and boiler manufacturer, as indicated below, and test sites for the third candidate boiler are actively being screened. The investigative program on the third boiler will be combined in a cooperative joint venture with Combustion Engineering in a test of their new "rich fireball" firing concept for the further reduction of NO_x emissions in tangentially fired boilers.

Tests in progress are:

- Columbus and Southern Ohio Electric Company
  Conesville, Unit No. 5 (410 MW)
  Tangential firing with overfire air (5 pulverizers)
  Manufacturer: Combustion Engineering, Inc.
  Start of Testing: December 1978
  Corrosion Panels Installed: Nov./December 1979
  Ultrasonic Thickness Measurements: December 1979
  Corrosion Probes: 30, 300, 1000 hours completed July 1980
- Louisville Gas and Electric Company
  Mill Creek, No. 3 (450 MW)
  Horizontally Opposed Firing-Low NO_x Burners (4 pulverizers)
  Manufacturer: Babcock & Wilcox Company

Start of Testing: March 1979

Corrosion Panels Installed: December 1979

Ultrasonic Thickness Measurements: December 1979

Corrosion Probes

Corrosion probes provide a relatively simple, quick and economical means for determining corrosion rates. Even though corrosion rate data developed in these and previous programs could not readily be related to actual furnace tube experience, this type of measurement is being continued in the long-term corrosion investigations with the objective of eventual correlation with rates developed by ultrasonic measurement of actual furnace tubes and from exposure of furnace tube test panels.

Corrosion probes in the Gulf Power Company, Crist No. 7 tests were exposed for 30, 300 and up to 1000 hours to show the effect of corrosion with time. The type of probe used in this and prior tests conducted by Exxon Research is shown in Figure 5. The orientation of the coupons on this probe at 90° to the furnace wall came under criticism as being unrealistic to furnace tube orientation and results, therefore, were viewed as being unreliable.

To overcome this problem probes designed and built by Combustion Engineering's corrosion research section are being used in the present contract. Design of the new probe is shown in the schematic sketch in Figure 6. Note that the corrosion probe coupons (Figure 6) are installed in a 4"x10" inspection door in the plane of the furnace wall parallel to the furnace tubes, simulating furnace tube exposure. In this position only half of the coupon is exposed to the furnace atmosphere; the same as furnace tubes.

Five of the new probes were used on the Conesville, No. 5 boiler to obtain corrosion data under 30, 300, and 1000 hours exposure. Four of the probes were located in the burner area in panels 2, 4, 5, and 6 (Figure 7) with the fifth probe installed in panel 1, outside of the burner area, to

obtain "control" data. Similarly, the location of the four probes which will be used on the Louisville No. 3 boiler is shown in Figure 8. The large rectangles on Figure 7 and 8 are test panels and the corrosion probes are represented by the smaller rectangles (in inspection doors).

Furnace Tube Test Panels

The schematic sketches depicted in Figures 7 and 8 show the location of the furnace tube corrosion test panels and corrosion probes installed in the Conesville, No. 5 and Louisville, No. 3 boilers, respectively. Because the area of greatest expected corrosion in the Conesville tangentially fired No. 5 boiler is in the vicinity of the front and rear furnace walls adjacent to smallest angle between the flame and the wall (Figure 7), panel locations in these walls were chosen judiciously to provide the greatest amount of information. Note that five panels are located in the front wall and three in the rear wall. Panels 2, 3, 4, 5, 6 and 7 are located in the burner area (greatest expected corrosion) with panels 1 and 8, above and below the burners for "control" purposes. Panels 2, 4 and 6 are in the most vulnerable areas closest to the flame while panels 3 and 6 are somewhat further from the flame but still in corrosion prone areas.

The sketch in Figure 8 shows locations of the furnace panels in the horizontally opposed fired Louisville, No. 3 boiler. Panels 4, 5 and 6 in the left and right walls are in the most vulnerable corrosion areas. Panels 1 and 2 are located in the hopper slopes where corrosion in this type of boiler has also been experienced but to a lesser extent. Panel 3, in the rear wall between the burners, covers the possibility of corrosion in the burner walls and panel 7, far above the burners, will provide "control" information.

As indicated above, installation of the corrosion panels in the Conesville and Louisville boilers was completed in December 1979. One half of each panel in both boilers is scheduled for removal during the annual outage in December 1980. Interim ultrasonic tube thickness measurements are also scheduled to be made on the furnace tubes and the panels at that time.

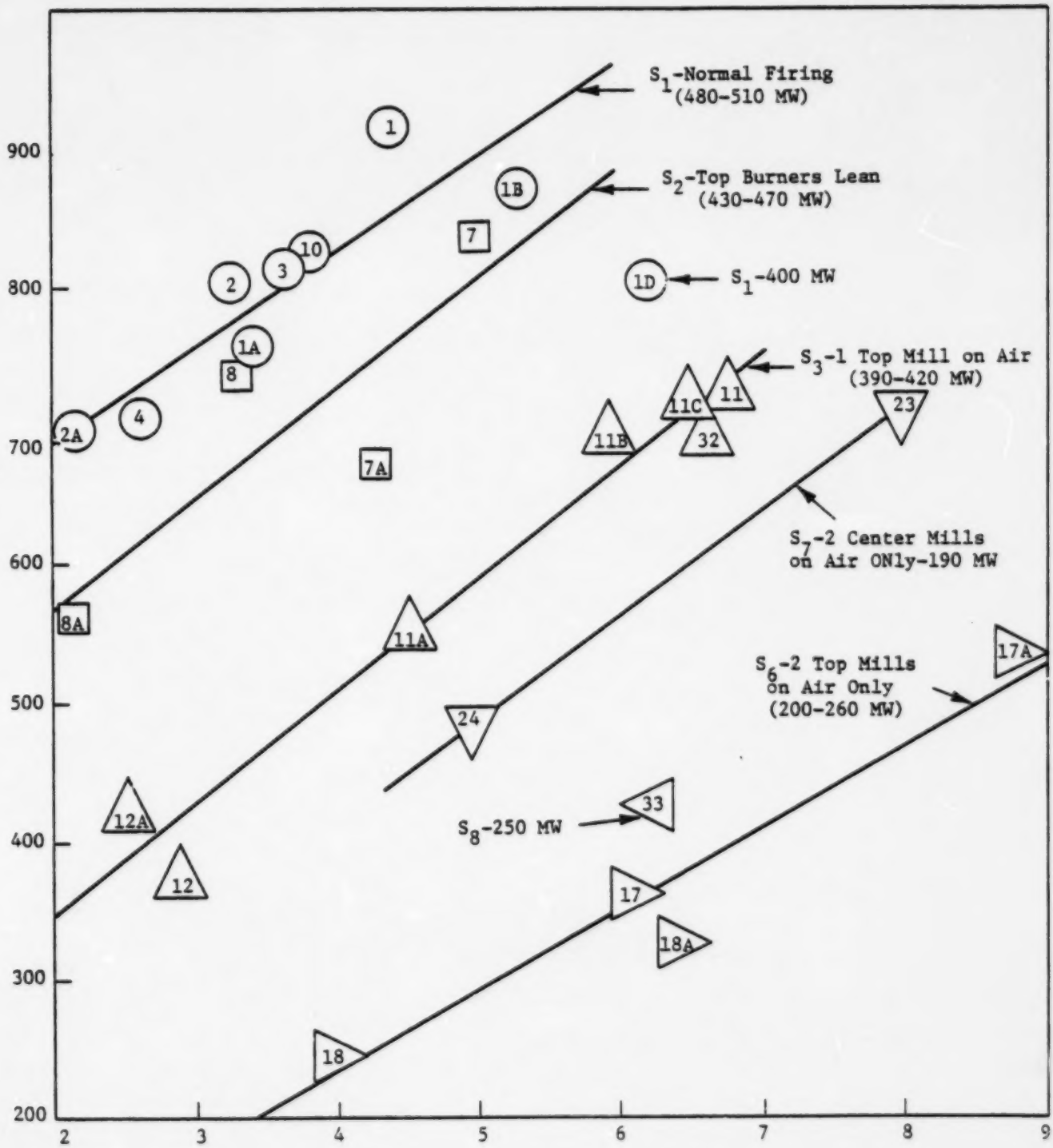
REFERENCES

1. Bartok, W., Crawford, A. R., and Piegari, G. J., "Systematic Field Study of NO_x Control Methods for Utility Boilers," Esso Research and Engineering Company Final Report No. GRU.4G.NO.71; (EPA No. APTD 1163, NTIS No. PB 210739), December, 1971.

2. Crawford, A. R., Manny, E. H., and Bartok, W., "Field Testing: Application of Combustion Modifications to Control NO_x Emissions from Utility Boilers," EPA-650/2-74-066, NTIS NO. PB-237344, Exxon Research and Engineering Company Final Report, June 1974.

3. Crawford, A. R., Manny, E. H., and Bartok, W., "Control of Utility Boiler and Gas Turbine Pollutant Emissions by Combustion Modification - Phase I," EPA-600/7-78-036a (NTIS No. PB 281078), Exxon Research and Engineering Company report, EPRI Project No. 200, March 1978.

4. Bowen, J. S., and Hall, R. E., "Proceedings of the Third Stationary Source Combustion Symposium;" Volume 1. Utility, Industrial, Commercial, and Residential Systems, EPA-600/7-79-050a, February 1979, page 157.



Average % Oxygen Measured in Flue Gas

Figure 1. PPM NO_x vs. % Oxygen in Flue Gas (Crist No. 7 Unit)

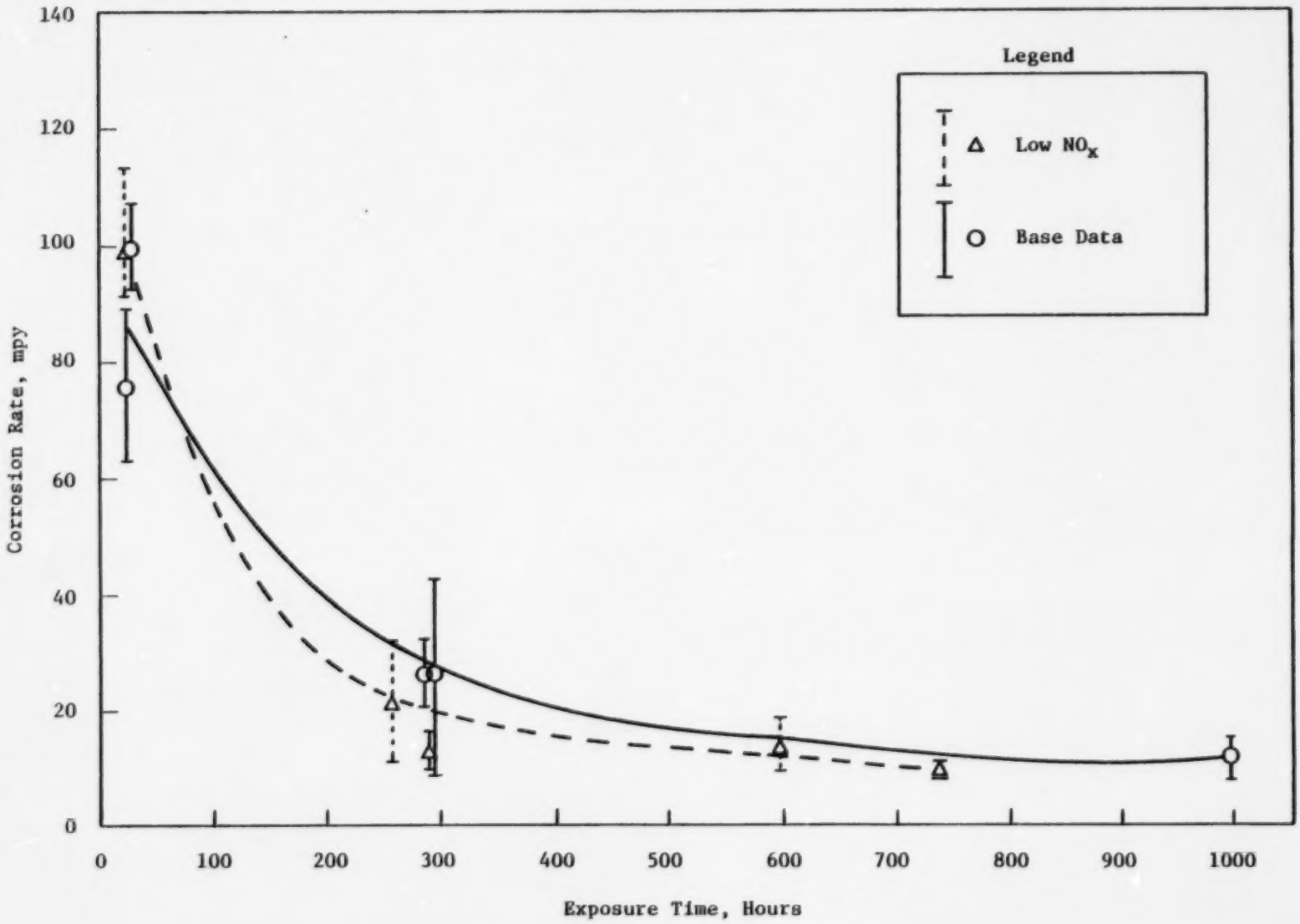


Figure 2. Comparison of Corrosion Rates
Gulf Power Company, Crist Station, Boiler No. 7
Pulverized Coal Firing.

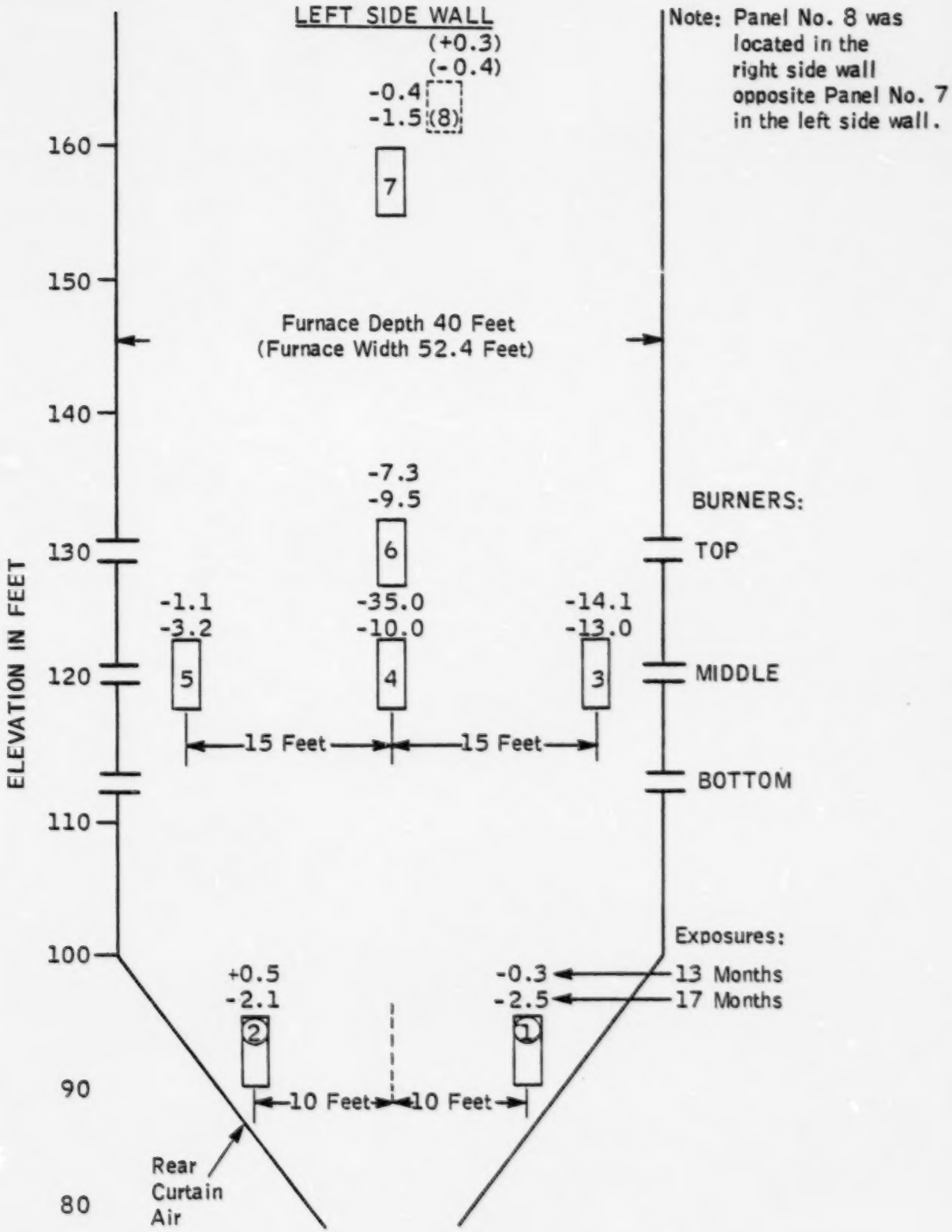


Figure 3. Test panel measurements and locations (average change in tube wall thickness - mils).

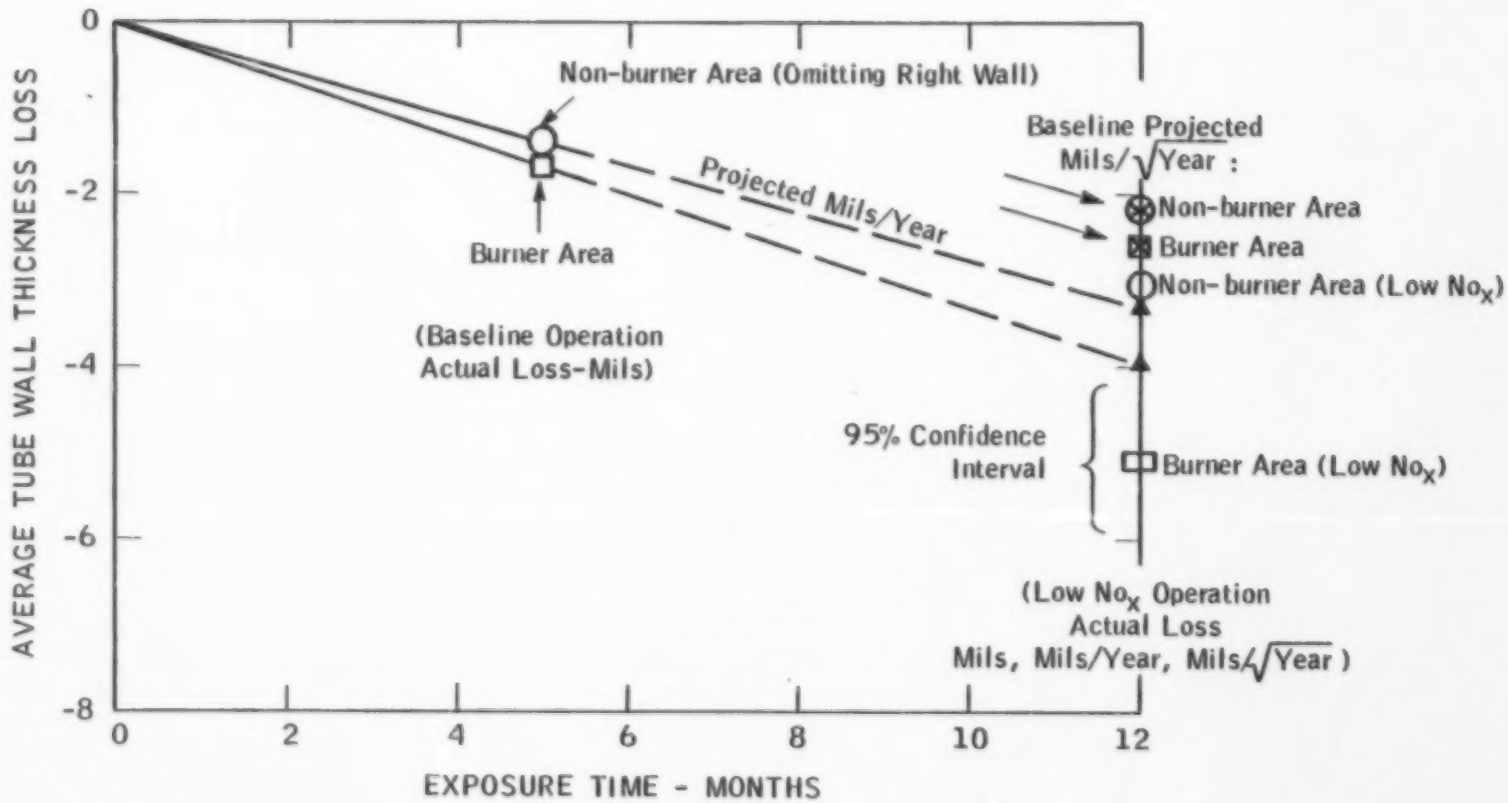


Figure 4. Comparison of 5 month baseline and 12 month low NO_x corrosion data.

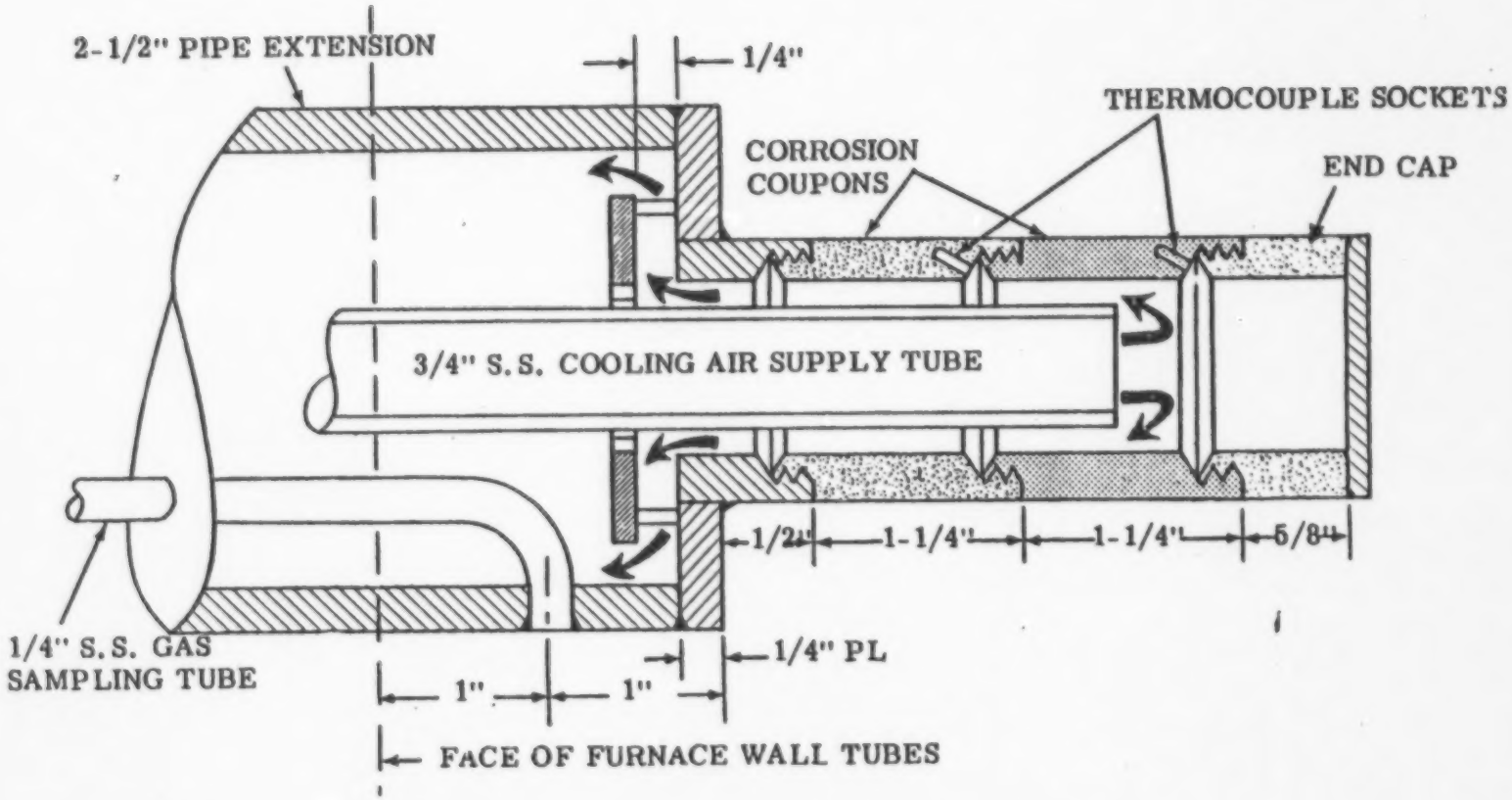


Figure 5. Corrosion probe, detail of corrosion coupon assembly (inside of furnace).

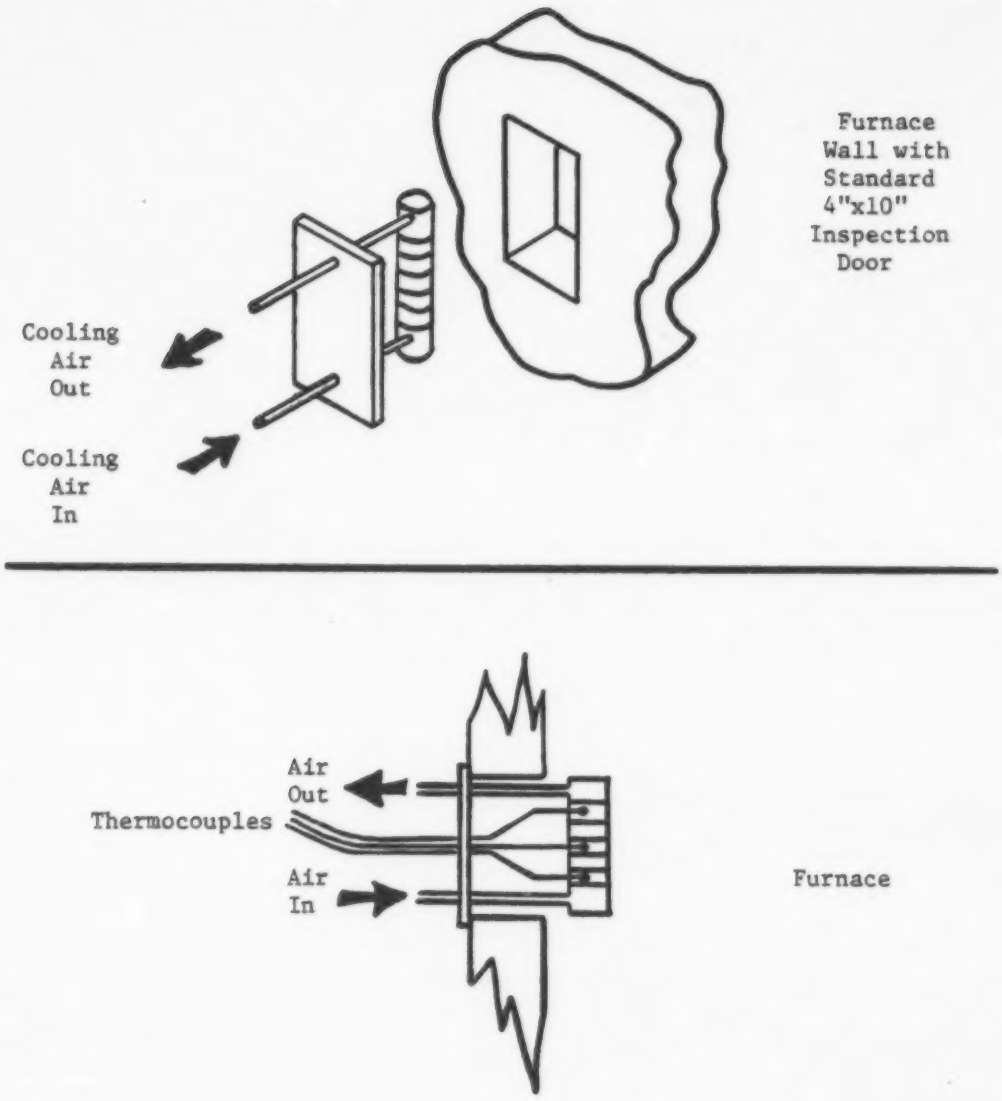


Figure 6. Corrosion probes
(Redrawn from C. E. Design)

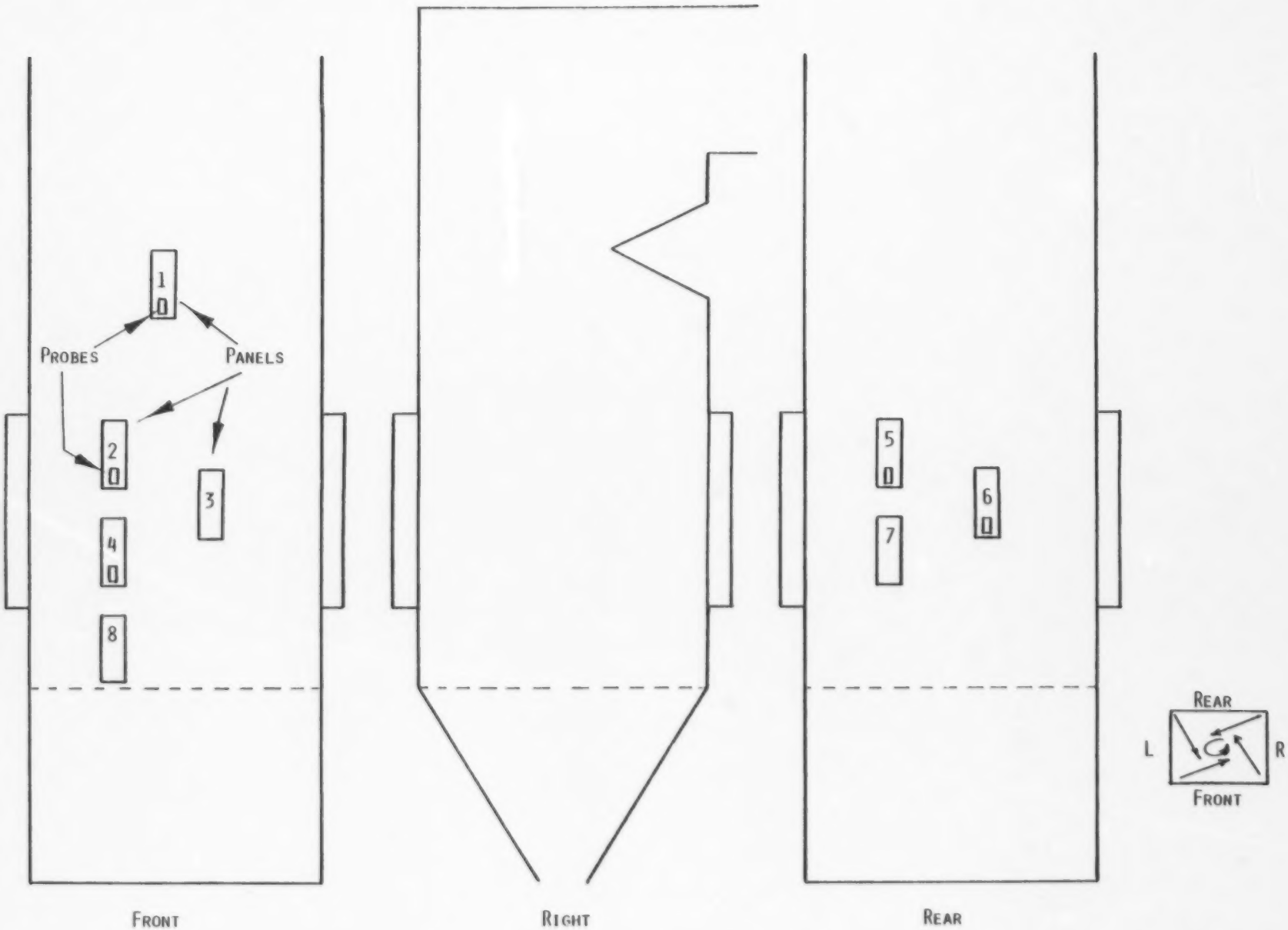


FIGURE 7. CORROSION PROBE AND TEST PANEL LOCATIONS
CSOE, CONESVILLE, NO. 5 BOILER.

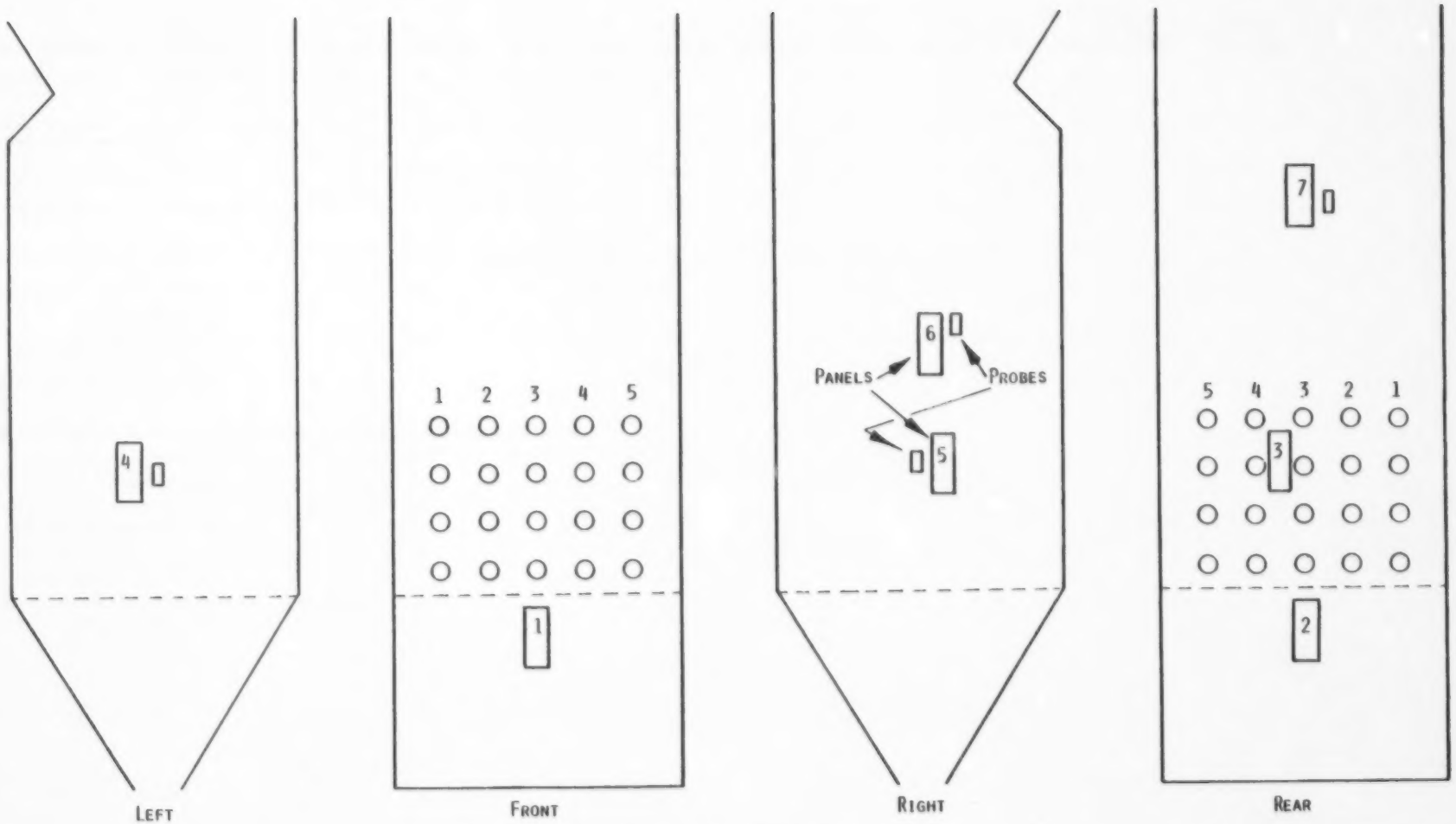


FIGURE 8. CORROSION PROBE AND TEST PANEL LOCATIONS
LG&E, MILL CREEK, NO. 3 BOILER.

TABLE 1

SUMMARY OF COAL AND MIXED FUEL FIRED BOILERS TESTED DURING PHASE I

	Boiler Operator	Station and Boiler No.	Boiler Mfr.(a)	Type of Firing(b)	Fuel(c) Burned	MCR (MWe)	No. of Burners	Test Variables	No. of Test Runs	NO_x Emissions: Baseline ppm(lb/10^6 BTU)	NO_x Emissions: Low NO_x ppm(lb/10^6 BTU)	NO_x Emissions: % NO_x(h) Reduction
1.	Tennessee Valley Authority	Widows Creek - 5	B&W	RW	C	125	16	4	31(d)	597 (0.81)	468 (0.64)	22
2.	Southern Electric Generating Company	E. C. Gaston - 1	B&W	HO(e)	C	270	18	5	37(d)	389 (0.53)	278 (0.38)	29
3.	Alabama Power Company	Barry - 2	CE	T(f)	CG	130	16	6	38	341 (0.46)	189 (0.26)	45
4.	Potomac Electric Power Company	Morgantown - 1	CE	T	CO	575	40	5	27	552 (0.75)	403 (0.55)	27
5.	Salt River Project	Navajo - 2	CE	T(f)	C	800	56	4	36(d)	492 (0.67)	282 (0.38)	43
6.	Public Service Company of Colorado	Comanche - 1	CE	T(f)	C	350	20	4	30(d)	417 (0.57)	261 (0.35)	37
7.	Public Service Electric and Gas Company	Mercer - 1	FW	FW(g)	C	270	24	4	33(d)	1383 (1.88)	876 (1.19)	37
	Average of Coal Fired Boilers								33	656 (0.89)	433 (0.59)	36

(a) B&W - Babcock and Wilcox, CE - Combustion Engineering, FW - Foster Wheeler

(b) RW - rear wall, HO - horizontally opposed, T - tangential, FW - front wall

(c) C - coal, C-G - coal-gas mixed, C-O - coal-oil mixed

(d) Particulate and corrosion probe tests performed on these boilers

(e) Special low NO_x emission burners

(f) Overfire air ports

(g) Wet bottom furnace

(h) % NO_x reduction at full or near full load

(i) PPM NO_x - 3% O_2, dry basis

TABLE 2

SUMMARY OF UTILITY UNITS TESTED DURING PHASE II

	Boiler Operator	Station and Boiler No.	Boiler Mfr.(a)	Type of Firing(b)	Fuel Burned	MCR (MWe)	No. of Burners	Test Variables	No. of Test Runs	NO_x Emissions: Baseline ppm (lb/10^6 BTU)	NO_x Emissions: Low NO_x ppm (lb/10^6 BTU)	% NO_x(g) Reduction
1.	East Kentucky Power Cooperative, Inc.	Cooper - 2	B&W	FW	Coal	220	18	4	101 (c)(d)	(h)557 (0.76)	(h)433 (0.59)	22
2.	Public Service Company of Colorado	Comanche - 2	B&W	HO(e)	Coal	350	32	3	18 (c)	726 (1.00)	278 (0.38)	62
3.	Public Service Electric and Gas Company	Sewaren - 5	B&W	HO	Oil	330	24	5	24	311 (0.40)	211 (0.27)	32
4.	Houston Lighting and Power Company	Wharton - 43 (Gas Turbine)	GE	(f)	Gas	50	--	2	16	212 (0.29)	34 (0.044)	84
5.	Houston Lighting and Power Company	Wharton - 42 (Gas Turbine)	GE	(f)	Oil	50	--	2	13	382 (0.45)	40 (0.048)	90
6.	Louisville Electric and Gas Company	Mill Creek - 1	GE	T	Coal	330	20		(c)	533 (.71)	- (i)	-
7.	Gulf Power Company	Crist - 7	FW	HO	Coal	300	24	4	158 (c)(d)	827 (1.1)	570 (.76)	31
	Average of Coal Fired Boilers								92	661 (.88)	427 (.37)	38

(a) B&W - Babcock and Wilcox, GE - General Electric, CE - Combustion Engineering

(b) FW - Front Wall, HO - Horizontally Opposed, T - Tangential

(c) Particulate tests performed on these boilers

(d) Corrosion probe tests performed on this boiler

(e) Overfire air ports

(f) Water injection

(g) % NO_x reduction of full or near full load

(h) PPM NO_x - 3% O_2, dry basis

(i) Additive test at baseline conditions only

TABLE 3

PARTICULATE EMISSION TEST RESULTS

Utility	Date	Test No.	Firing Condition	Load, MW	Emissions mg/m^3	Emissions GR/SCF	Emissions ng/J	Emissions Lb/10^6 Btu	Req. Eff. To Meet 0.1 Lb/ 10^6 Btu	% Carbon On Particulate	Coal Ash Wt, %	HHV. Wet Cal/g Btu/Lb
East Kentucky Power Cooperative, Inc., Cooper Station, Boiler No. 2	3/9/77	41	Base*	178	1.06	4.65	3280	7.63	98.7	1.48	12.78	11,742
	3/11/77	43	Base*	155	.72	3.12	2361	5.49	98.2	.94	12.48	12,217
	3/25/77	59	Low NO_x*	123	.78	3.41	2520	5.86	98.3	1.81	11.30	12,312
	3/28/77	60	Low NO_x*	123	.87	3.82	3130	7.28	98.7	1.87	10.47	12,291
Public Service Electric & Gas Company Sewaren Station Boiler No. 5	9/17/76	4D	Base**	288	.0059	.026	17.2	0.04	-	-	-	-
	9/17/76	6C	Low NO_x**	280	.0063	.0274	17.2	0.04	-	-	-	-
Gulf Power Company, Crist Station, Boiler No. 7	6/20/78	150	Base*	436	.686	3.00	2301	5.35	98.1	-	-	-
	6/21/78	151	Low NO_x*	432	.874	3.82	1926	4.48	97.8	2.98	12.45	11,263
	6/22/78	152	Base*	417	.864	3.78	2881	6.70	98.5	0.87	16.48	10,782
	6/23/78	153	Low NO_x*	434	.909	3.97	2468	5.74	98.3	1.71	14.32	11,033

*Pulverized coal firing.
**Oil firing.

EHM:jbg

TABLE 4

PARTICLE SIZE DISTRIBUTION, WT%

EAST KENTUCKY POWER COOPERATIVE
COOPER STATION - BOILER NO. 2

PULVERIZED COAL FIRING

	Baseline Firing			LOW NO_x Firing		
Size Range	Test No. 41	Test No. 43	Average	Test No. 59	Test No. 60	Average
>2.5	98.86	92.68	94.8	95.65	91.75	93.7
2.5	2.04	3.71	2.9	3.28	5.34	4.3
1.5	0.50	1.24	0.9	0.78	1.32	1.1
1.0	0.41	0.95	0.7	0.61	1.07	0.8
0.5	0.63	1.13	0.9	1.04	1.65	1.4
<0.5	0.36	0.62	0.5	0.67	1.11	0.9

TABLE 5

PARTICLE SIZE DISTRIBUTION, WT%

GULF POWER COMPANY
CRIST STATION - BOILER NO. 7
PULVERIZED COAL FIRING

	Baseline Firing			LOW NO_x Firing		
Size Range	Test No. 150	test No. 152	Average	Test No. 151	Test No. 153	Average
>2.5	93.10	94.00	93.6	92.50	89.80	91.2
2.5	2.15	3.48	2.8	3.15	3.68	3.4
1.5	0.90	0.72	0.8	1.12	1.94	1.5
1.0	0.83	0.84	0.7	0.83	1.43	2.3
0.5	1.24	01.20	1.2	1.16	1.84	1.5
<0.5	1.80	0.72	1.3	1.24	1.33	01.3

TABLE 6

SUMMARY OF BOILER PERFORMANCE CALCULATIONS

	Boiler No.	Firing Mode	Test No.	Load, MW	% O_2	NO_x Emissions, (3% O_2) PPM	Lb/10^6 Btu	ng/J	Coal Ash, % (Wet Basis)	% Carbon on Particulate	Boiler Efficiency,
East Kentucky Power Cooperative Inc, Cooper Station	2	Baseline	41	178	4.2	612	0.82	351	12.37	1.48	89.82
	2	Baseline	43	155	5.4	574	0.77	329	12.76	0.94	90.12
	2	Low NO_x	59	123	5.0	381	0.51	218	11.30	1.81	90.44
	2	Low NO_x	60	123	6.6	490	0.65	281	10.41	1.87	90.36
Gulf Power Company, Crist Station	7	Low NO_x	151	432	3.1	508	0.68	291	12.45	2.98	88.92
	7	Baseline	152	417	5.5	848	1.13	486	16.48	0.87	88.86
	7	Low NO_x	153	430	1.9	456	0.61	261	14.32	1.71	89.27

TABLE 7

SUMMARY OF ANTI-SLAGGING ADDITIVE TEST RESULTS

Test No.	Date	Time		Hours @ Full Load (325-330 MW)	O_2, %	NO_x PPM (3% O_2)	Test Condition
200	6/11/79	07:27	Start				Baseline
		13:53		12	5.0	584	(No Additive)
		16:16			5.3	599	
		19:27	End				
201	6/13/79	10:00	Start				Baseline
		11:06		12	4.7	512	(No Additive)
		15:36			5.2	566	
		22:00	End				
202	6/14/79	10:00	Start				
		13:18		4.5	5.0	557	Baseline
		*14:30	End				(No Additive)
		16:15	Load Cut Back				
203	6/18/79	07:00	Start				Baseline
		08:16			4.8	448	(No Additive)
		13:45		12	4.8	479	
		15:58			4.9	517	
		19:00	End				
204	6/20/79	07:10	Start				Additive
		09:26			4.5	447	(15 GPH)
		13:35		15	4.6	473	
		16:00			4.6	572	
		22:20	End				
205	6/21/79	08:15	Start				Additive
		09:38			5.3	514	(15 GPH)
		13:00		17	5.3	534	
		15:35			5.7	581	
		01:15	End				
206	6/25/79	09:00	Start	12	-	-	Additive
		21:00	End				(7.5 GPH)
207		09:30	Start	14	-	-	Additive
		23:10	End				(15 GPH Slugs)

*SH/RH sprays max. @ 14:30.

TABLE 8

TEST PANEL MEASUREMENTS
(Average Change in Tube Hot Side Wall Thickness)

Test Panel Number and Location	Baseline[1] Operation-5 Mo. (5/76 to 10/76)			Low NO_x[2] Operation-12 Mo. (11/76 to 4/78)		"Low NO_x"[3] Operation-4 Mo. (12/77 to 4/78)		"Mixed"[4] Operation-13 Mo. (5/76 to 11/77)			"Mixed"[5] Operation-17 Mo. (5/76 to 4/78)		
	Mils	(n)	Mils/Yr.	Mils	(n)	Mils	(n)	Mils	(n)	Mils/Yr.	Mils	(n)	Mils/Yr.
Non-Burner Area (20 Feet Below Burners)													
1. Left Wall-Front	-1.9	(6)	-4.6	-1.2	(4)	+1.3	(20)	-0.2	(34)	-0.2	-2.5	(51)	-1.8
2. Left Wall-Rear (28 feet above burners)	-2.4	(8)	-6.0	+0.4	(5)	+1.4	(20)	+0.5	(34)	+0.5	-2.1	(51)	-1.5
7. Left Wall-Center	-2.3	(6)	-5.4	+1.3	(5)	+1.1	(18)	-0.4	(30)	-0.4	-1.5	(42)	-1.1
8. Right Wall-Center	-		-	-		+1.9	(20)	+0.3	(34)	+0.3	-0.4	(51)	-0.3
Average	-2.20	(20)	-5.33	+0.17	(14)	+1.42	(78)	+0.05	(132)	+0.05	-1.62	(195)	-1.18
Burner Area (Middle Burner Level)													
3. Left Wall-Front	-1.7	(7)	-4.2	- 8.7	(4)	+1.6	(18)	-14.1	(30)	-12.9	-13.0	(42)	-9.2
4. Left Wall-Center	-1.5	(7)	-3.5	-12.8	(3)	+1.4	(18)	-35.0	(30)	-32.3	-10.0	(40)	-7.1
5. Left Wall-Rear (Top Burner Level)	-4.4	(5)	-10.6	-		+1.4	(18)	- 1.1	(30)	- 1.0	- 3.2	(42)	-2.3
6. Left Wall-Center	-2.6	(8)	-6.4	- 9.7	(4)	+2.4	(18)	- 7.3	(30)	- 6.7	- 9.5	(45)	-6.7
Burner Area Average	-2.55	(27)	-6.2	-10.40	(11)	+1.70	(72)	-14.4	(120)	-13.3	- 8.92	(169)	-6.30
Grand Average	-2.40	(47)	-5.72	- 5.12	(25)	+1.56	(150)	-7.16	(252)	-6.61	- 5.28	(364)	-3.73

(n) Number of paired measurements used in calculation average tube wall thickness changes.

(1) 5 tubes per panel. Initial measurements in laboratory; final measurement in the field.
(2) 3 tubes per panel. Initial measurements in the field; final measurements in the laboratory.
(3) 2 replacement tubes per panel. Initial measurement in the field; final measurement in the laboratory.
(4) 2 tubes per panel. Initial and final measurements made in the laboratory.
(5) 3 tubes per panel. Initial and final measurements made in the laboratory.

TABLE 9

COMPARISON OF FIELD AND LABORATORY MEASUREMENTS

Panel No.:		Field Measurements: 5 Month Baseline Operation	Field Measurements: 12 Month "Low NO_x" Operation	Lab Measurements: 17 Month "Mixed" Operation	Lab Measurements: Estimated 12 Month "Low NO_x" Operation*
Outside Burners					
1		-1.9	-1.2	-2.5	-0.6
2		-2.4	+0.4	-2.1	+0.3
7		-2.3	+1.3	-1.5	+0.8
	Average	-2.20	+0.17	-2.03	+0.17
Inside Burners					
3		-1.7	-8.7	-13.0	-11.3
4		-1.5	-12.8	-10.0	-8.5
5		(-4.4)	-	(- 3.2)	-
6		-2.6	-9.7	-9.5	-6.9
	Average	-1.93	-10.40	-10.83	-8.90

*17 month "mixed" operation minus 5 month baseline operation = estimated 12 month "low NO_x" operation measurements.

TABLE 10

WALL TUBE HOT SIDE METAL THICKNESS CHANGE RATE-MILS/YEAR
(Paired Data)

LEVEL MEASURED RELATIVE TO BURNERS	BASELINE OPERATION - 5 MONTHS					"LOW NOx" OPERATION - 12 MONTHS				
	FURNACE WALL				FURNACE AVERAGE	FURNACE WALL				FURNACE AVERAGE
	LEFT	RIGHT	FRONT	REAR		LEFT	RIGHT	FRONT	REAR	
NON BURNER AREA										
1	-3.62	-12.96	+1.10	-	-7.49	-3.89	+0.81	-2.92	-1.50	-1.94
2	-3.24	-10.66	-5.74	-0.31	-5.66	-4.45	+0.07	-4.04	-4.10	-2.96
6	-0.30	- 5.30	-	-9.05	-5.74	-2.48	+0.04	-	+0.21	-0.51
$\bar{x}$	-3.17	-10.56	-3.24	-3.62	-6.24	-3.94	+0.36	-3.37	1.84	-2.11
n	73	85	22	29	209	102	94	55	89	340
sp	5.57	6.47	4.59	4.86	5.78	4.71	3.40	3.47	5.43	4.42
BURNER AREA										
3	+1.75	- 9.41	-4.27	-1.49	-3.24	-4.99	-7.14	-4.31	-3.46	-5.48
4	+0.10	- 2.11	-4.30	-3.74	-2.06	-8.26	-3.49	-2.68	-5.11	-4.86
5	-5.57	-10.18	-7.30	+0.41	-6.74	-7.17	-2.47	-3.51	-4.13	-4.41
$\bar{x}$	-1.51	- 6.94	-5.21	-1.73	-3.98	-6.24	-5.29	-3.50	-4.17	-5.05
n	54	56	29	29	168	83	91	48	54	276
sp	4.49	5.59	4.80	4.13	4.88	6.77	4.78	3.71	6.00	5.55
$\bar{\bar{x}}$	-2.46	- 9.12	-4.36	-2.68	-5.23	-4.97	-2.42	-3.431	-2.72	-3.43
n	127	141	51	58	377	185	185	103	143	616

TABLE 11

COMPARISON OF 5-MONTH BASELINE AND 12-MONTH LOW NO_x AVERAGE TUBE WALL THICKNESS LOSS DATA

Area	Low NO_x 12 Months Mils, Mils/Year, Mils/$\sqrt{Year}$	Baseline 5 Months Mils	Baseline 5 Months Mils/Year	Baseline 5 Months Mil/$\sqrt{Year}$
Nonburner:				
Left Wall	-3.94	-1.32	-3.17	-2.04
Right Wall	+0.36	-4.40	-10.56	-6.82
Front Wall	-3.37	-1.35	-3.24	-2.09
Rear Wall	-1.84	-1.51	-3.62	-2.34
Total	-2.11	-2.60	-6.25	-4.03
Less Right Wall	-3.05	-1.37	-3.30	-2.12
	-4.6 to -1.5 95% simultaneous confidence limits			
Burner:				
Left Wall	-6.24	-0.063	-1.51	-0.98
Right Wall	-5.29	-2.89	-6.94	-4.48
Front Wall	-3.50	-2.17	-5.21	-3.36
Rear Wall	-4.17	-0.72	-1.73	-1.12
Total	-5.05	-1.66	-4.00	-2.58
	-6.0 to -4.1 95% simultaneous confidence limits			

TABLE 12

QUALITATIVE SUMMARY OF CORROSION MEASUREMENTS

Method Used to Obtain Corrosion Measurements		Baseline Operation	Low NO_x Operation	Low NO_x vs. Baseline Operation
1. Furnace Wall Tubes (Ultrasonic)		Burner area equal to nonburner area	Burner area loss greater than non-burner area loss	Low NO_x loss > baseline within burner area
2. Test Panel Tubes (Ultrasonic)		No significant differences (except panel No. 5)	Burner area loss greater than non-burner area loss	Low NO_x loss > baseline within burner area. Low NO_x loss < baseline outside burner area
3. Probe Coupons (Weight)	One Day Exposure	Burner area loss greater than non-burner area	Burner area loss greater than NO_x burner area loss	No significant difference
	10-42 Days Exposure	No significant difference	No significant difference	No significant difference

NO_x EMISSIONS CHARACTERISTICS OF ARCH-FIRED FURNACES

By:

T. W. Sonnichsen
KVB, Inc.
Irvine, California 92714

J. E. Cichanowicz
Electric Power Research Institute
Palo Alto, California 94303

ABSTRACT

Field tests have been conducted on three subbituminous pulverized-coal arch-fired utility boiler configurations. The objective of these tests was to determine as-found NO_x emission levels and the influence of combustion modifications on these emissions. These configurations are unique in that the coal is introduced downward from the arch into the furnace with the bulk of the combustion air added through the front wall perpendicular to the flame jet. Staged combustion conditions are thereby generated which have been shown to be conducive to low NO_x emissions.

Corrected NO levels ranged from 200 ppm to 350 ppm. The lowest emissions were emitted from the largest (275 MW) boiler. Variations in excess air, air flow injection distribution between burner and front wall and burner stoichiometry were shown to reduce NO emissions by 5 to 35 percent. A discussion of these results is presented.

INTRODUCTION

Promulgation of New Source Performance Standards (NSPS) by the U.S. Environmental Protection Agency (EPA) for coal-fired utility boilers has created significant interest in developing suitable low-NO_x combustion systems. Several programs under boiler manufacturer, EPA and EPRI sponsorship (1-5) have been underway directed at developing new burner/boiler design concepts. All of these designs in one manner or another use a staged combustion process which has been shown to be the most practical means of achieving reduced NO_x emissions.

An alternative to these new burner/boiler configurations is the arch-fired furnace. Boilers of this design are characterized by (A) burners situated in the furnace arch, oriented vertically and firing down into the furnace and (B) a significant portion (up to 80 percent) of the combustion air supplied through the furnace frontwall along the flame front perpendicular to the flame jet. A long U-shaped flame is thereby generated with inherent staged combustion conditions. This method of firing has acquired several descriptions including "arch-fired," "vertically-fired," "down-fired," "U-flame," and "down-shot." The terms "arch-fired" and "vertically-fired" have been used interchangeably during this study. The arch-fired design should not be confused with other firing configurations which, although fired from the top of the furnace downward, introduce all combustion air at the burner. These boilers, therefore, do not have the inherent staged combustion conditions of the arch-fired design and consequently do not have corresponding low NO_x emission characteristics.

Arch-fired boilers have been used in utility applications for over sixty years. Boilers of this general configuration were the first to successfully

use pulverized coal combustion. Development of subsequent designs contributed significantly to modern design concepts (7). Modern use of arch-firing in the United States has been limited to three subbituminous coal-fired boiler configurations used by the Wisconsin Electric Power Company (WEPCo) and several applications to anthracite coal-fired boilers (8).

This paper presents a discussion of arch-firing as a low-NO_x design approach for subbituminous coal combustion in utility boilers. The boilers considered in this study are the three WEPCo configurations. Descriptions of these boiler designs are presented together with results of field tests conducted to characterize NO emissions. Comparisons are made between the emission characteristics of the arch-fired boilers. A discussion is presented identifying in a speculative manner the significant combustion parameters conducive to low-NO_x.

This study was conducted as part of an EPRI sponsored program to investigate the use of arch-firing as an alternative utility boiler design. The results of this study are documented in an EPRI report, "NO Emissions from Pulverized Coal Vertically-Fired Boilers" (9). An economic evaluation of the use of arch-firing has been conducted by Foster Wheeler Energy Corporation (10).

BOILER DESCRIPTIONS

The three boiler configurations are unique having been custom designed by engineers at WEPCo. The smallest boilers, with a capacity of 80 MW, are located at the Port Washington Generating Station. The two other designs are at the Oak Creek Generating Station. The 125-MW boilers are located in the North Plant while the 275-MW boilers are in the South Plant. Nine boilers were included in the test program: four of the 80-MW class (Boilers 2, 3, 4, and 5), three of the 125-MW class (Boilers 1, 2, and 4), and two of the 275-MW size (Boilers 5 and 6).

A summary of the design parameters for the three boiler configurations is presented in Table I. This information is provided as reference for interested utility and manufacturing engineers. A brief description of the furnace

design factors follows. More comprehensive descriptions of these boilers can be found in References 8 and 9.

The general arrangement of the three boiler types are illustrated in Figure 1. The boilers share several common design features as well as having individual characteristics. In all three, the burners are located in the furnace arch, are oriented vertically and fire down into the furnace. The pulverized coal for these boilers is prepared and temporarily stored above the burners in bins. Feeders control the flow of pulverized coal into the primary air stream that transports the coal through the burner and into the furnace. Ignition occurs approximately three to five feet from the burner outlet, producing a flame jet that penetrates to the bottom of the furnace. Combustion air is added around the burner (termed secondary air) and from the front wall perpendicular to the flame jet. Front wall air is introduced into the furnace through slits between the front wall watertubes.

The final common design feature of these units is the incorporation of radiant superheat and reheat heat transfer in the furnace. These elements were included in the original design to improve low-load steam temperatures and overall operating efficiency. In essence, however, this design results in heat transfer characteristics in the furnace that differ from those of conventional waterwall furnaces. Close control of the combustion conditions in the furnace is also required in order to maintain proper steam conditions. Excessive steam tube temperatures are controlled primarily by overall boiler excess air. In all three designs, the furnace front wall and division walls under the arch (where present) consist of watertubes. The furnace side and back walls consist of steam tubes.

The primary differences between the WEPCo boilers (other than capacity) involve (a) the burner design and combustion air distribution, generating differing near burner combustion conditions, (b) the arrangement of the burners and (c) the presence of division walls.

The design of the burners used on the 80 MW and 125 MW boilers is simple, consisting of tapered pipes with a four pronged helix inside near the burner tip. The helix is used to impart swirl to the pulverized coal/primary air stream. The burners used on the 275 MW boilers, on the other hand, are much

more complex. A diagram of the burners used on the 275 MW boilers is presented in Figure 2. The pulverized coal is transported from the feeder to the burner by scavenging air. The primary air is spiraled around the coal stream generating a hollow cylinder of pulverized coal injected into the furnace. The balance of the combustion air is supplied both at the burner and from the furnace front wall. The additional air supplied at the burner passes through the two concentric cones shown in Figure 2. The inner cone converges to generate high velocity air that assists the flame jet in penetrating to the bottom of the furnace. The outer cone diverges to produce low velocity combustion air in the immediate vicinity of the burner tip. Both cones have non-adjustable vanes to impart swirl to the incoming air. Modifications have been made to block approximately 50 percent of the outer cone inlet area. There is no available hardware to control secondary air flow to individual burners in a cell.

The arch-fired designs also differ in the number and arrangement of the burners and the presence of division walls. These factors are illustrated in Figure 3. The 80 MW boilers are fired through 20 burners arranged in a single line evenly spaced across the length of the arch. There are no division walls used on this design. The 125 MW are fired through 16 burners also arranged in a single line but separated into four groups of four. The presence of water-tube division walls underneath the arch between these burner groups form four furnace "cells." The sixteen burners on the 275 MW design have also been separated into four groups of four. The arrangement of these burners, as shown in Figure 3, is significantly different. The burners in each group are configured in a "trapezoidal" pattern forming two rows of burners across the arch. The outer row of burners (farthest from the furnace front wall) are therefore somewhat shielded from the front wall air by the inner row of burners. The division walls on the 275 MW boilers extend across the furnace and up into the initial convective passes. The furnace is thereby effectively separated into four sub-furnaces operating somewhat independently.

NO EMISSIONS MEASUREMENT RESULTS

Presented in this section are the results of the NO emission testing conducted on the three arch-fired boiler designs. The test program on each boiler consisted of two parts: (1) a baseline characterization to determine as-found emission levels and the influence on NO levels of excess air, and (2) combustion modification tests directed at determining the effect of alterations in the inherent staged combustion conditions on NO emissions. The available flexibility of combustion air distribution along the flame jet and burner stoichiometry through burners-out-of-service operation were used as the two methods of implementing staged combustion. The following discussions follow this format, describing first the results of the baseline tests and then the combustion modification tests.

All tests conducted during this program used the coal customarily fired in these boilers. The primary coal sources for these boilers are located in Southern Illinois/Western Kentucky. The 125 MW boilers also periodically fire western coal from Wyoming. A summary of analyses for as-fired pulverized coal samples collected during the program are presented in Table II.

BASELINE NO EMISSION CHARACTERIZATION

The full load NO emissions for the three boiler types are presented in Figure 4. With the exception of one of the 80 MW boilers, the emissions data form three groups corresponding to the three boiler types. Note that the NO levels decrease with increasing boiler capacity. For all three designs, the NO levels increased with increased excess air.

The spread in the emission levels for three of the four 80 MW boilers (Port Washington Boilers 2, 4 and 5) was introduced by variations in the

excess air level. NO emissions are shown to increase by approximately 30 ppm for each one percent increase in flue gas O_2. The NO levels for the remaining unit (Boiler 3), however, were significantly lower, by 80 ppm at comparable O_2 levels. This difference between the emission levels from this boiler and the other three 80 MW units was partially attributed to the quantity of primary air flow. While the data presented in Figure 3 for Boilers 2, 4, and 5 represented operation at primary air pressures of 15 to 16 inches of water, the NO emissions data for Boiler 3 were obtained while operating at 13 inches of water. To further investigate this, NO emissions were measured over a range of primary air pressure on Boilers 2 and 3. While these data indicated a strong dependence of NO on primary air pressure (10 to 15 ppm per one inch H_2O increase in primary air pressure in this range), the NO emissions from Boiler 3 at comparable primary air pressures were still 50 ppm below those of the remaining three boilers. This difference has not been completely resolved.

Also presented in Figure 4 are the emission levels for the three 125 MW boilers tested (Oak Creek Boilers 1, 2 and 4). Boilers 1 and 4 operated at nearly full capacity, while Boiler 2 had a maximum load of 92 MW due to convective superheat tube metal temperature limitations. Emissions for Boilers 1 and 4 are shown to be comparable. Operation of Boiler 2 at the lower load required higher excess air and consequently produced higher NO levels. The limited data presented in Figure 4 indicate a sensitivity of approximately 20 ppm NO decrease with each 1 percent decrease in O_2. This was confirmed by the more extensive test series conducted at lower loads.

The composite NO emission data for loads in excess of 225 MW for both 275 MW boilers are also included in Figure 4. As shown, corrected NO emissions were between 190 and 205 ppm, with the highest emissions corresponding to the peak load of 265 MW. Failure to achieve full load (275 MW) and limitations in excess air flexibility were due to excessive steam tube element temperatures. Increased flexibility in excess air was available at 200 MW operation. Results of tests conducted at this reduced load are shown in Figure 5. Furnace exhaust O_2 ranged from 6 to 10 percent, with corresponding NO levels increasing from 175 to 250 ppm, an increase of 20 ppm NO per

1 percent O_2. These data suggest the possibility of additional NO reductions of 30 to 50 ppm with reductions in excess air to levels corresponding to 4 percent O_2--levels that had been achieved previously on individual 80 MW and 125 MW boilers. Operation at this excess air level was not possible on the 275 MW boilers due to excessive tube metal temperatures.

As mentioned previously, the 275 MW boilers are divided into four cells by division walls, effectively producing four independent sub-furnaces. Some variation was noted between the NO emission levels of the four furnace cells comprising each of these boilers. NO emissions differed by as much as 25 ppm at comparable excess air levels. The reasons for this could include manageable differences (heat input, combustion air distribution, coal feed distribution) and several other nonmanageable conditions (furnace slagging and subtle differences in burner hardware). The causes of the differences between the cells were investigated but never fully identified.

COMBUSTION MODIFICATION TESTS

The initial combustion modification tests conducted on the arch-fired boilers were directed at investigating the impact on NO emissions of changes in the front wall air addition patterns along the flame front. These tests were made possible by the compartmentalized front wall windboxes, especially on the 80 MW and 125 MW boiler configurations which are equipped with three levels of secondary air injection along the flame path. Distribution of combustion air between the secondary to front wall air on the 275 MW boilers was less straightforward due to the more complex burner design.

A second series of combustion modification tests were conducted on each boiler type involving burners-out-of-service operation to increase the fuel richness in the initial flame region. On the 80 MW and 275 MW boilers, lack of suitable hardware precluded the removal of individual burners from service. Instead, coal flow through individual feeders was stopped resulting in the associated pair of burners being removed from service. Shutoff dampers were available on the 125 MW boilers allowing individual burners to be removed from service.

NO emissions on the 80 MW boilers were shown to be significantly influenced by the distribution of front wall air addition. The measured distribution of air flow from primary (P), secondary (S) and the three front wall levels (F1, F2, F3) and resulting furnace NO emissions are presented in Figure 6. As shown in Figure 6, decreasing the proportion of combustion air flow through the lowest air levels (farthest from the burner) by adjusting sidewall air position increased NO emissions. NO emissions at base condition (all sidewall dampers wide open) increased from 275 ppm to 325 ppm with the lower dampers half closed and to 340 ppm with the lower dampers closed. As noted in Figure 6, the proportion of air flow to the upper two levels increased as did the proportion of secondary air introduced around the burner, thus maintaining constant total air flow. Primary air flow remained constant.

Similarly, NO emissions decreased as the front wall air was biased to the lower levels. Operation with the top level of dampers closed on Boiler 3 reduced NO by approximately 15 ppm from the full open position. Repeating these tests on Boiler 2 decreased NO levels by 45 ppm (8% reduction) by stopping the air flow to the top level.

Operation with two of the ten feeders out of service (4 of the 20 burners) on Boiler 2 reduced NO by approximately 50 ppm. Operation at this condition with all dampers full open and 4 percent O_2 at 55 MW achieved NO emissions of 200 ppm, the lowest levels reached during testing on the 80 MW class boilers.

Typical results of the front wall air distribution tests conducted on the 125 MW boilers is shown in Figure 7. NO emissions were shown to be relatively insensitive to front wall air distribution. Measured air distribution patterns are presented in Figure 7. If anything, NO emissions increased slightly as air was biased to the lower levels, that is, closing the top level dampers. It should be noted that numerous combinations of full and partially closed dampers were tried on all three 125 MW class boilers with results consistent with those presented in Figure 7.

A series of tests were conducted on Boiler 4 (125 MW), with two and four burners out of service, to investigate the impact on NO emissions of gross flame stoichiometry in the near burner region. Results from these tests

indicated a relatively small impact on NO emission levels. NO emissions decreased by up to 30 ppm depending on the pattern of burners out of service.

Combustion modification tests conducted on the 275 MW boilers were limited to (A) changes in the combustion air distribution between the secondary and front wall air and (B) biasing the coal feed between the inboard and outboard burner pairs. Operation with a feeder out of service was not attempted as this would have resulted in severe disruptions in tube element temperatures. Similarly, operation with individual burners out of service could not be applied since there were no coal shutoff dampers to individual burners. Other procedures that could potentially have been employed to alter the combustion process, such as (A) varying the secondary air flow between the four burners in a cell or (B) changing the primary or secondary air swirl, were also not possible due to hardware limitations.

The combustion modification tests discussed in this section were conducted on cells 2 and 3 only. Tests showed that these interior cells (controlling the radiant superheat areas of the furnace) had somewhat more flexibility and were amenable to the modifications imposed without causing severe boiler upset. While the results are limited to one cell, the trends in the emissions are taken to be characteristic of the entire boiler.

The results of the series of tests of redistributing the secondary and tertiary air flows are presented in Figure 8. These data represent operation at a reduced load of 200 MW with consistent cell exhaust O_2 concentrations of 6 percent. Biasing air flow to the front wall decreased NO emissions by 10 to 25 ppm. Similar adjustments to the combustion air distribution in Cell 3 resulted in a somewhat larger NO reduction. The differences in NO reductions between the cells were investigated but not resolved.

A brief series of tests were conducted on cell 2 to determine the effects of varied coal feed distribution on NO emissions. From a base condition, feeder speeds were varied to provide a biasing of the coal first to the outboard feeder (delivering coal to the outer burner pair) and then to the inboard feeder (delivering coal to the burner pair next to the front wall). Biasing the coal away from the front wall decreased NO by ~10 ppm, while biasing towards the front wall increased NO by a similiar amount.

FLY ASH CARBON CONTENT MEASUREMENTS

Fly ash samples were extracted from the flue gases upstream of the air preheater and analyzed for carbon content using ASTM procedures (11). Excessive fly ash carbon content is, of course, an indication of incomplete combustion and could be a factor limiting the application of staged combustion.

The results of the data on fly ash carbon concentration obtained during the test program are presented in Figure 9 as a function of furnace exhaust NO. Although a significant degree of scatter is present, it is evident that carbon content generally increased as the NO decreases. This was especially true for the 275 MW class boilers. It has been speculated that the high carbon content from these boilers is due to the multiple burner rows with the outboard flame jet somewhat screened from the front wall air addition. Additional investigation into causes of the trend shown in Figure 9 will be necessary in order to propose solutions and the impact on NO emissions. It should be noted that the data presented in Figure 9 represent as-fired conditions with no attempts to optimize the potential tradeoffs of NO and high carbon content.

DISCUSSION

It is interesting to note from the results presented in the previous section that the NO_x emission levels from the three arch-fired boiler designs decreased as the size and complexity of the combustion process increased. The lowest emissions were measured on the 275 MW design that had the largest proportion of combustion air introduced at the burner and therefore would have been expected to have less inherent staged conditions and correspondingly higher NO_x levels. Two explanations have been proposed to account for this: (A) the heat absorbing characteristics of the furnaces and (B) fundamental differences in the combustion processes between the boiler types. The purpose of this section is to discuss in a speculative manner the results of this test program in terms of these hypotheses.

FURNACE HEAT ABSORPTION

It has been demonstrated that reduced flame temperatures result in lower NO_x emissions (12). Large furnace volumes and/or furnace division walls providing increased heat absorbing surfaces could be expected to result in lower NO_x emissions. As discussed previously, there are significant differences between the furnaces configurations of the arch-fired furnaces, especially with regard to the division walls on the 275 MW design. This has been proposed as a possible explanation of the reduced NO_x emission from these boilers.

To test this hypothesis, estimates have been made of the volumes and available heat absorbing surfaces for three regions in each arch-fired design corresponding to: (A) the entire furnace, (B) the lower furnace below the plane of the arch and (C) the region directly below the arch.

A summary of the estimated volumes and surface areas of these regions is included in Table III together with heat absorption on a per unit volume and area basis. As shown in Table III by the consistent heat absorption, the three arch-fired boiler designs show a nearly proportional increase in volume and area as the size of the boiler increases. It would appear from these data that the hypothesis of the lower NO emissions on the 275 MW boilers due to size and heat absorption does not appear to be valid.

This analysis, however, does not take into account the location of the heat absorbing surfaces with respect to burner arrangement, flame jet mixing patterns and the medium (water or steam) transported through the furnace and division wall tubes. Each of these factors could significantly influence heat removal patterns in the flames and resulting NO_x formation.

DIFFERENCES IN THE COMBUSTION PROCESSES

The influence of differences in the inherent staged combustion processes on outlet NO_x emissions is much more complex. While the application of staged combustion has repeatedly been demonstrated as a practical means of achieving low NO_x emissions, the level of understanding of the fundamental nature of this process is generally low (12). Staged combustion has been conceptualized as reducing NO_x emissions by reducing the formation rate of both thermal and fuel NO_x. In addition, the destruction of NO to other products has been observed in the intermediate regions of one staged combustion process (13). It may be that competing or counterbalancing reactions occur within the flame structure that significantly affect final NO levels.

The complexity of understanding the NO_x formation/reduction processes in the arch-fired furnace design are compounded by the aerodynamic mixing patterns characteristic of these configurations. The inherent staged combustion process can be conceptualized as taking place in four steps: (A) the near burner region, (B) the intermediate stage, (C) lower furnace combustion and (D) burnout. These zones are identified in Figure 10 for the arch-fired design.

As discussed previously, significant differences exist between the burner designs of the 80 MW and 125 MW boilers, and that of the 275 MW configuration

that are reflected in the near burner mixing patterns identified as region A in Figure 10. The simpler burner arrangement produces a coal/air jet entering a region of relatively quiescent furnace gases. This situation is conducive to forming a well mixed jet in which the coal rich internal core is broken down relatively rapidly. The more complex burner on the 275 MW design produces a jet with a fuel rich central core surrounded by a concentric ring of air moving at comparable velocities. The resulting low levels of shear between these two streams could result in the fuel rich central core maintaining its integrity (and its fuel rich conditions) until well into the furnace. The longer residence times at fuel rich conditions could result in a decreased proportion of fuel nitrogen conversion to NO_x as opposed to the 80 MW and 125 MW designs.

Conceptually, the intermediate region (region B in Figure 10) would correspond to the region of entrainment of the front wall combustion air into the flame jet. Calculations have shown, however, that buoyancy forces in this region are important and tend to drive the relatively cold front wall air down the wall delaying mixing with the flame jet until into the lower furnace regions. This flow pattern shown in Figure 10 is also enhanced by front wall flow deflectors on the 125 and 275 MW arrangements. It can be speculated that oxygen deficient flame conditions exist within this intermediate region containing intermediate combustion products (H, CO, NH_3, HCN) that have been shown to reduce NO_x to N_2. This would be especially true of the outer row of burners in the 275 MW design that are partially shielded from penetration of the front wall air by the inner burner row. The inherent staged combustion process of the arch fired design, especially the 275 MW furnaces, may be extremely conducive to NO_x reduction.

The lower furnace region identified as region C in Figure 10 is also of interest. Results of earlier tests conducted on arch-fired designs demonstrated the lower regions to have the highest furnace temperatures (14). In this region mixing between the frontwall air and flame jet are still incomplete so that furnace geometry could play a significant role in NO_x formation by controlling local flame stoichiometry. It has been conceptualized that the application of arch-firing to boilers in the 600 MW

class will require an opposed fired design. The opposed flame interaction in this region could significantly alter NO_x formation and/or reduction patterns. Also, the possibility of NO_x formation from nitrogen contained in the char in the upper furnace burnout zone (region D) cannot be discounted. Again, the level of understanding of these processes is not complete enough to formulate any definitive answers.

CONCLUSIONS

- Arch-fired utility boilers with front wall air addition that have been in service for up to 40 years have demonstrated NO_x emission levels comparable to specially designed low NO_x combustion systems.
- It has been speculated that these low emission levels are attributable to combustion conditions similar to that found in the more sophisticated new designs.
- Assessment of the arch-fired configurations as a viable alternative to the modern low NO_x combustion systems will require economic and reliability comparisons which are now in progress.

REFERENCES

1. Barsin, J. A., "Pulverized Coal Firing NO_x Control," Proceedings: Second NO_x Control Technology Seminar, EPRI FP-1109-SR, July 1979.

2. Vatsky, J., "Experience in Reducing NO_x Emissions on Operating Steam Boilers," Proceedings: Second NO_x Control Technology Seminar, EPRI FP-1109-SR, July 1979.

3. Brown, Richard A., "Alternate Fuels and Low NO_x Tangential Burner Development Program," Proceedings of the Third Stationary Source Combustion Symposium, Volume II, Advanced Processes and Special Topics, EPA-600/7-79-050b, February 1979.

4. Zallen, D. M. et al., "The Generalization of Low Emission Coal Burner Technology," Proceedings of the Third Stationary Source Combustion Symposium, Volume II, Advanced Processes and Special Topics, EPA-600/7-79-050b, February 1979.

5. Johnson, S. A. et al., "An Advanced Low-NO_x Concept for Pulverized Coal Combustion," Proceedings: Second NO_x Control Technology Seminar, EPRI FP-1109-SR, July 1979.

6. Dornbrook, F. L., "Developments in Burning Pulverized Coal," Paper presented at the semi-annual meeting of the ASME, Milwaukee, Wisconsin, June 1948.

7. Orning, A. A., "The Combustion of Pulverized Coal," Chemistry of Coal Utilization, Volume II (John Wiley and Sons: New York), 1945.

8. Cichanowicz, J. E. et. al., "NO_x Emissions Characteristics of Down-Fired, Sequential Air Addition Furnaces," Proceedings: Second NO_x Control Technology Seminar, EPRI FP-1109-SR, July 1979.

9. Sonnichsen, T. W., "NO Emissions from Pulverized Coal Vertically-Fired Boilers," EPRI, Final report in preparation, Contract RP-1339-1.

10. Vatski, J., "Economic and Engineering Analysis of Arch-Fired Furnaces," EPRI Report in preparation, Contract RP-1339-2.

11. Laboratory Sampling and Analysis of Coal and Coke, ASTM D271-70.

12. Thompson, R. E. et al., "Assessment of NO_x Control Technology for Coal Fired Utility Boilers," Environmental Control Implications of Generating Electric Power from Coal, Appendix D, Argonne National Laboratory, ANL/ECT-3, December 1977.

13. Johnson, S.A. et al., "The Primary Combustion Furnace System--An Advanced Low-NO_x Concept for Pulverized Coal Combustion," Second EPRI NO_x Control Technology Seminar, Denver, CO, November 1978.

14. Tenney, E. J., "Practical and Theoretical Aspects of Firing Low Grade Bituminous Coal in Pulverized Form," Proc. 3rd Intern. Conf. Bituminous Coal, 2,370-399, 1931.

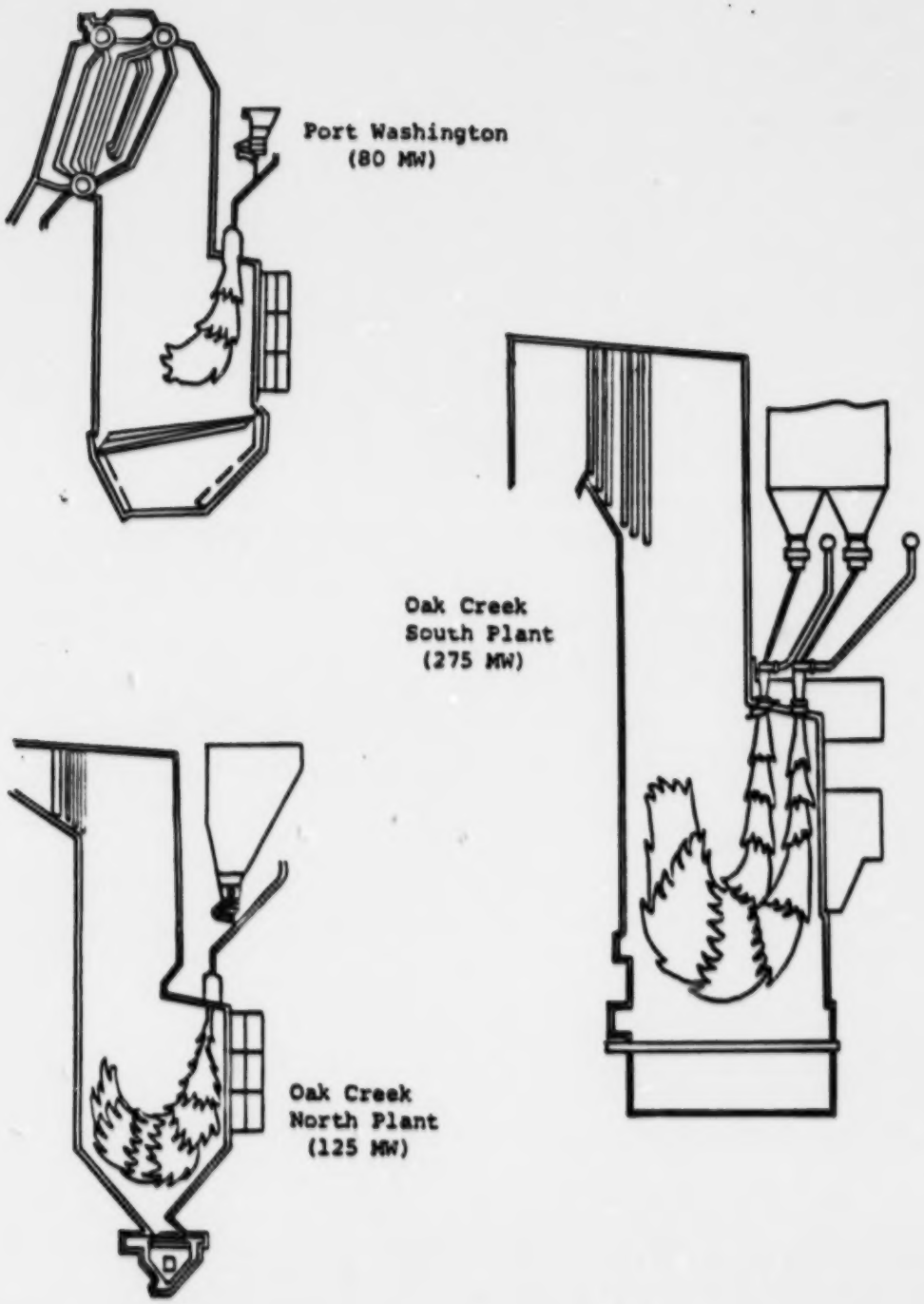


Figure 1. WEPCo arch-fired boilers

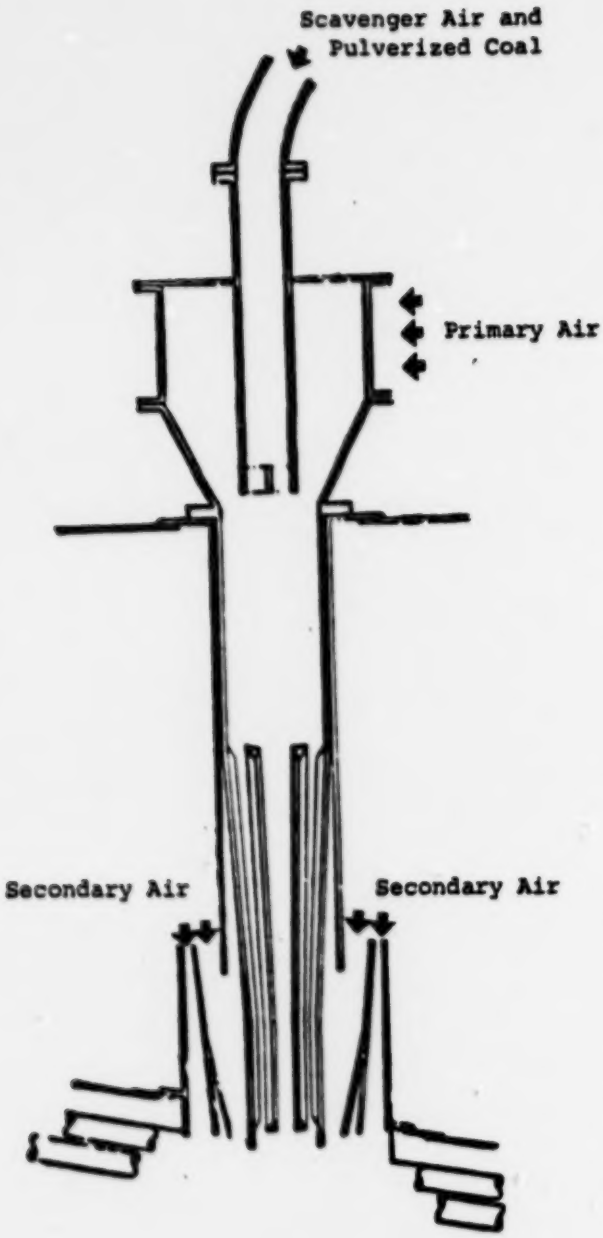


Figure 2. Oak Creek South Plant 275 MW Burner Configuration

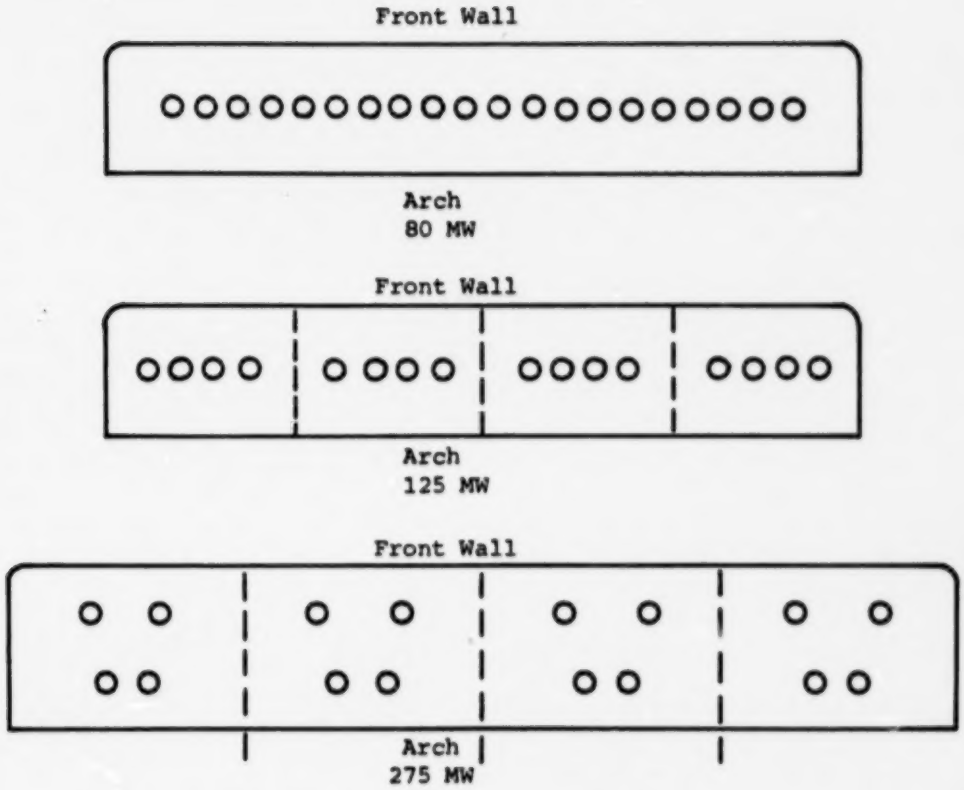


Figure 3. Arch arrangement of WEPCo furnaces - not to scale

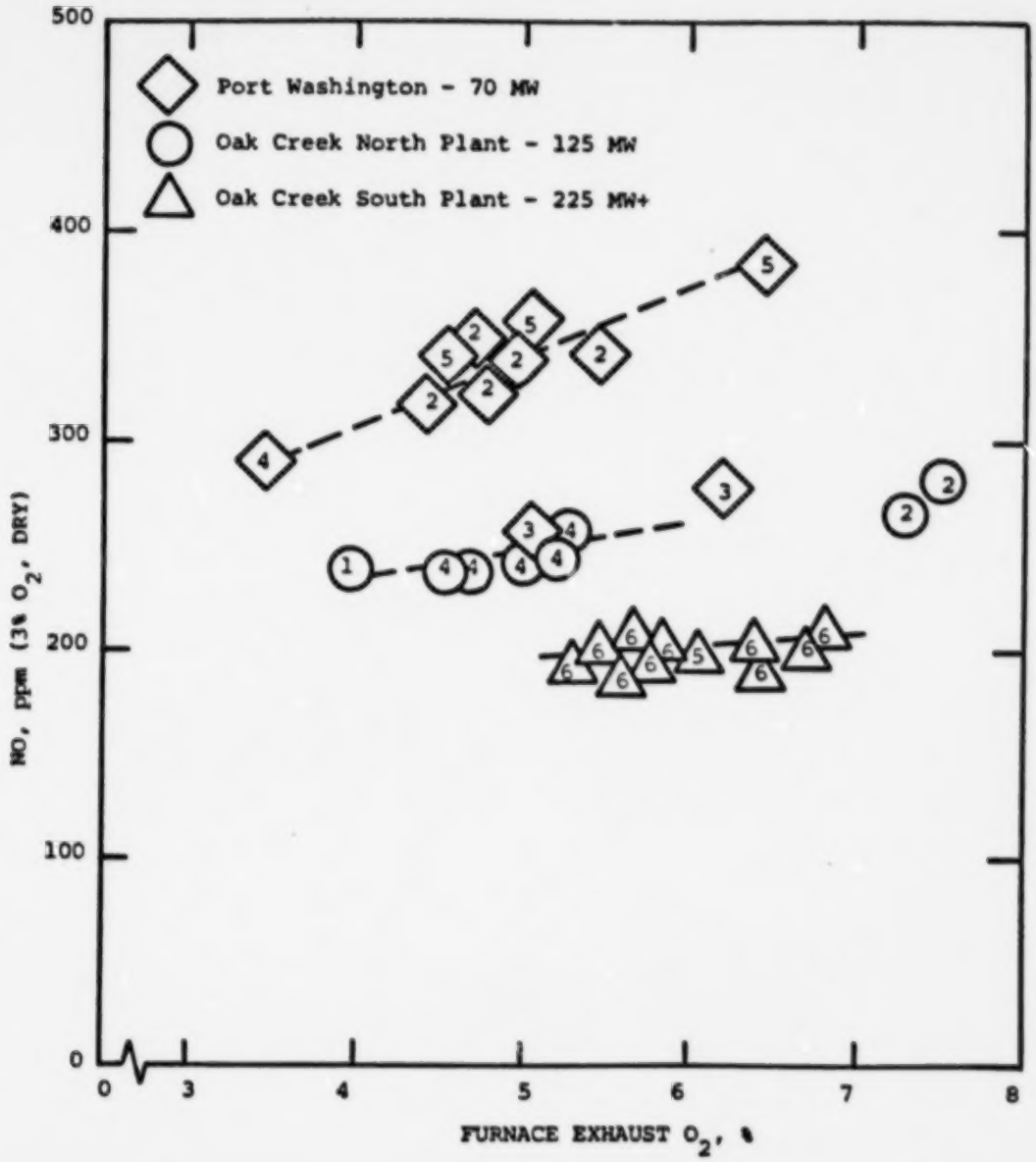


Figure 4. Full load baseline NO emissions, WEPCo arch-fired boilers. The numbers in the symbols denote the boiler numbers for each station.

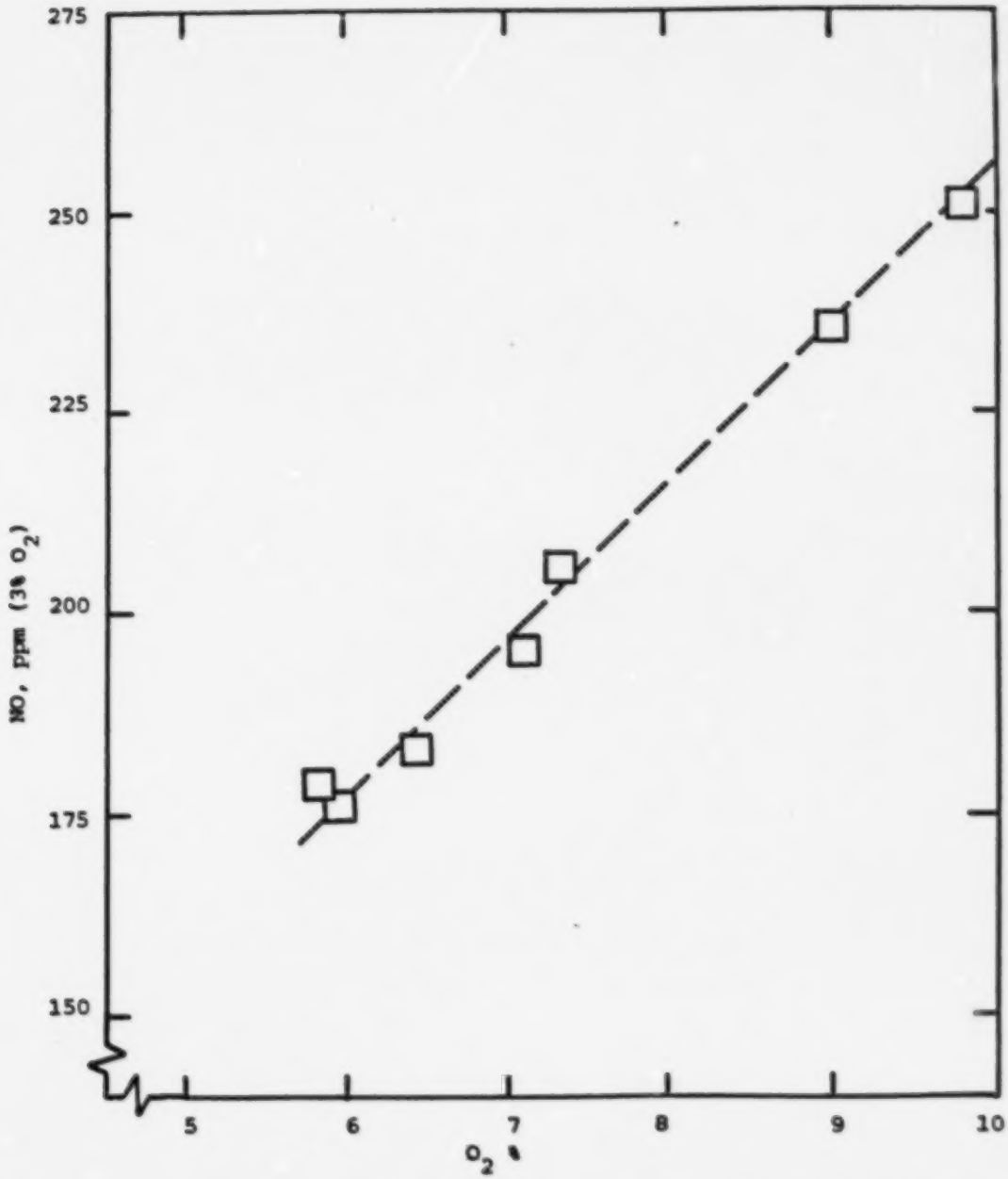


Figure 5. Composite NO Emissions as a Function of Excess Air, Oak Creek Boiler 6, 200 Mw

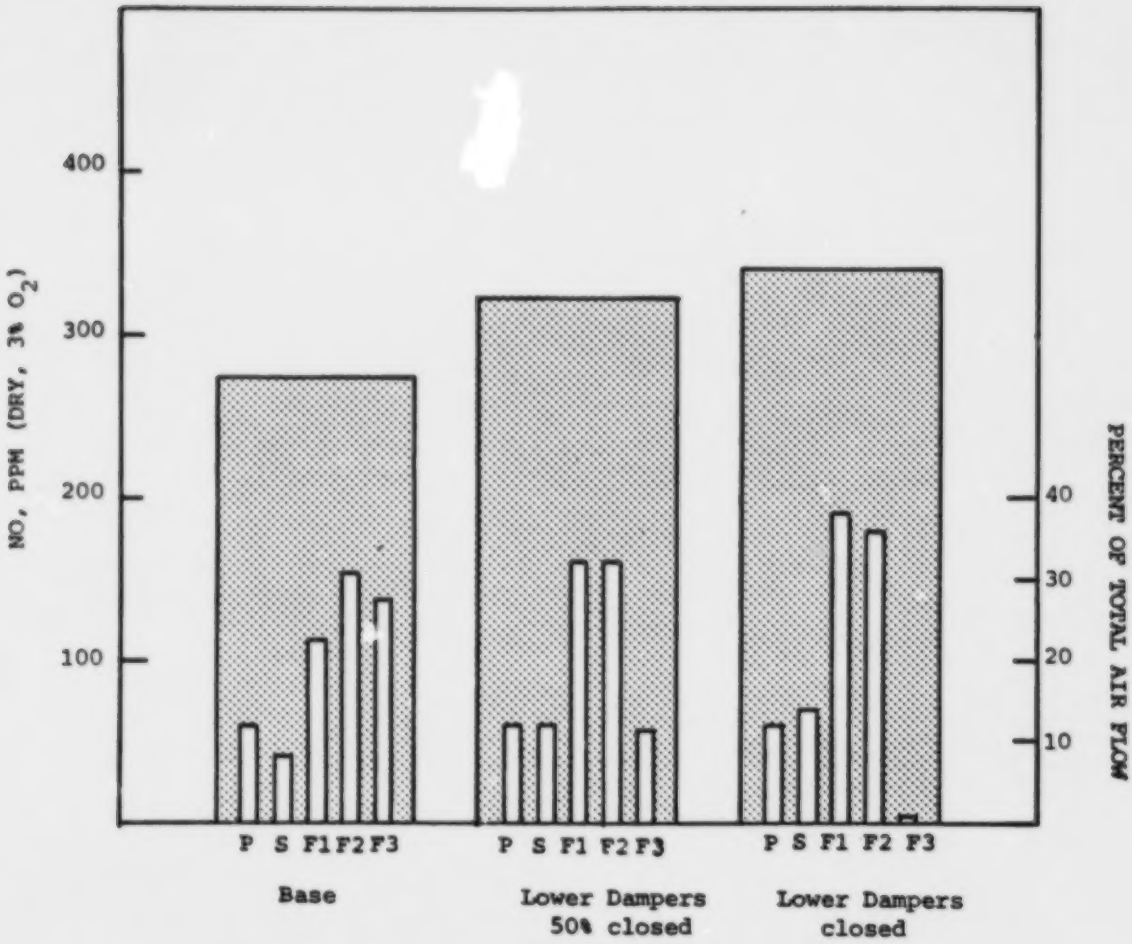


Figure 6. Impact of front wall air distribution on NO emissions, Port Washington Boiler 3 (80 MW), 55 MW, 6.5% O_2 (P-Primary Air Flow, S-Secondary Air Flow, F1-Front Wall Upper Level Air Flow, F2-Front Wall Mid Level Air Flow, F3-Front Wall Lower Level Air Flow)

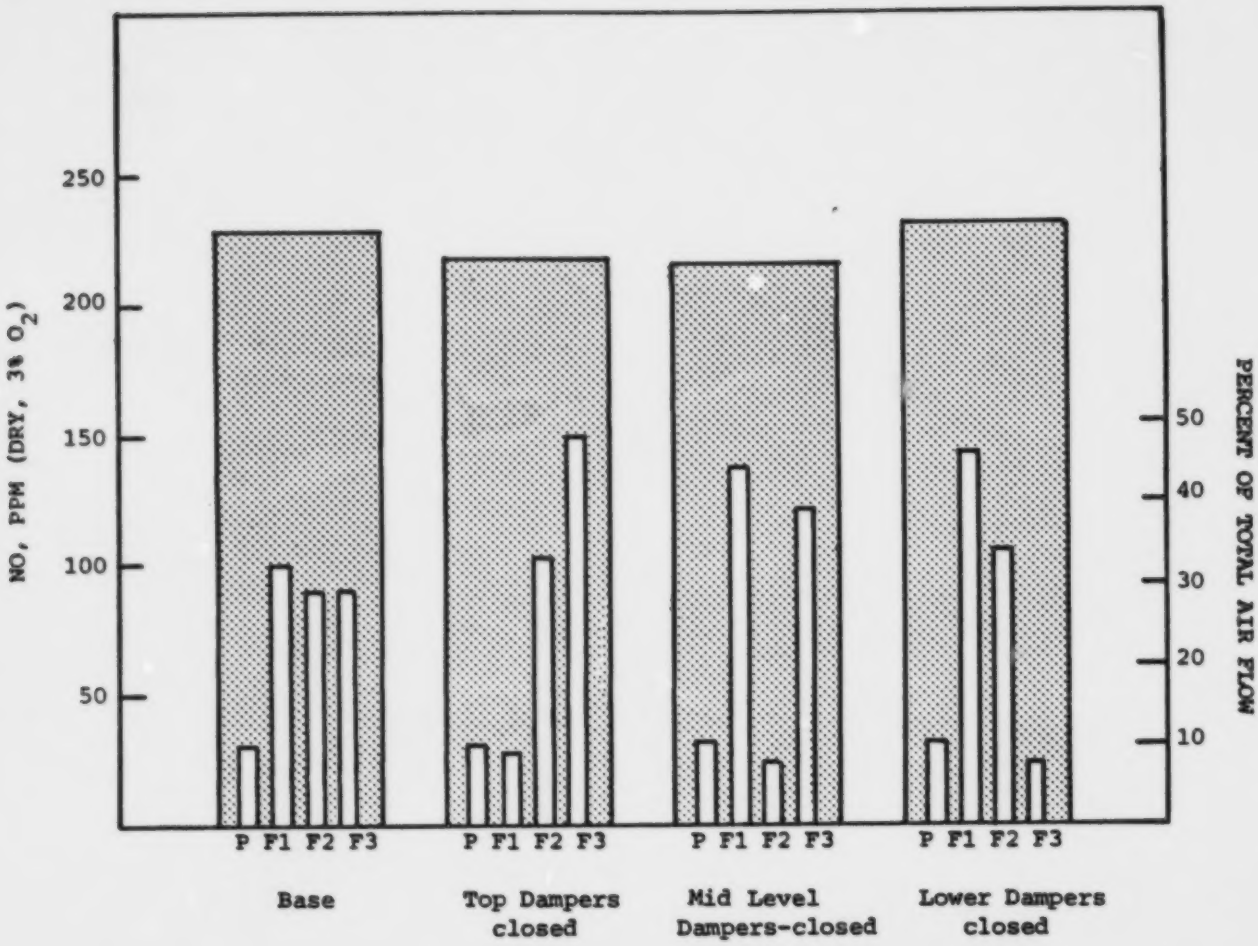


Figure 7. Impact of front wall air distribution on NO emissions Oak Creek Boiler (125 MW), 107 MW, 4.0% O_2 (P-Primary Air Flow, F1-Front Wall Uppper Level Air Flow, F2-Front Wall Mid Level Air Flow, F3-Front Wall Lower Level Air Flow)

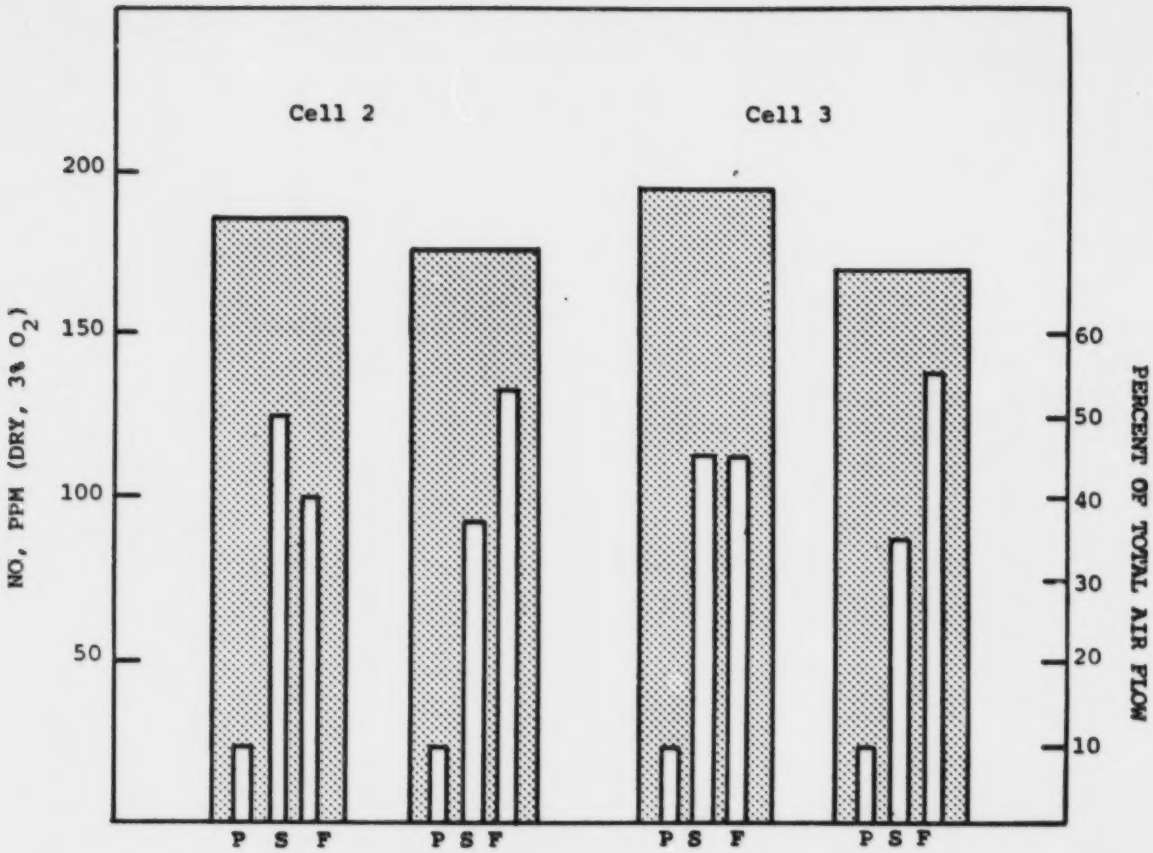


Figure 8. Impact of combustion air distribution on NO emissions Oak Creek Boiler 6 (275 MW), 200 MW, 7% O_2 (P-Primary Air Flow, S-Secondary Air Flow, F-Front Wall Air Flow)

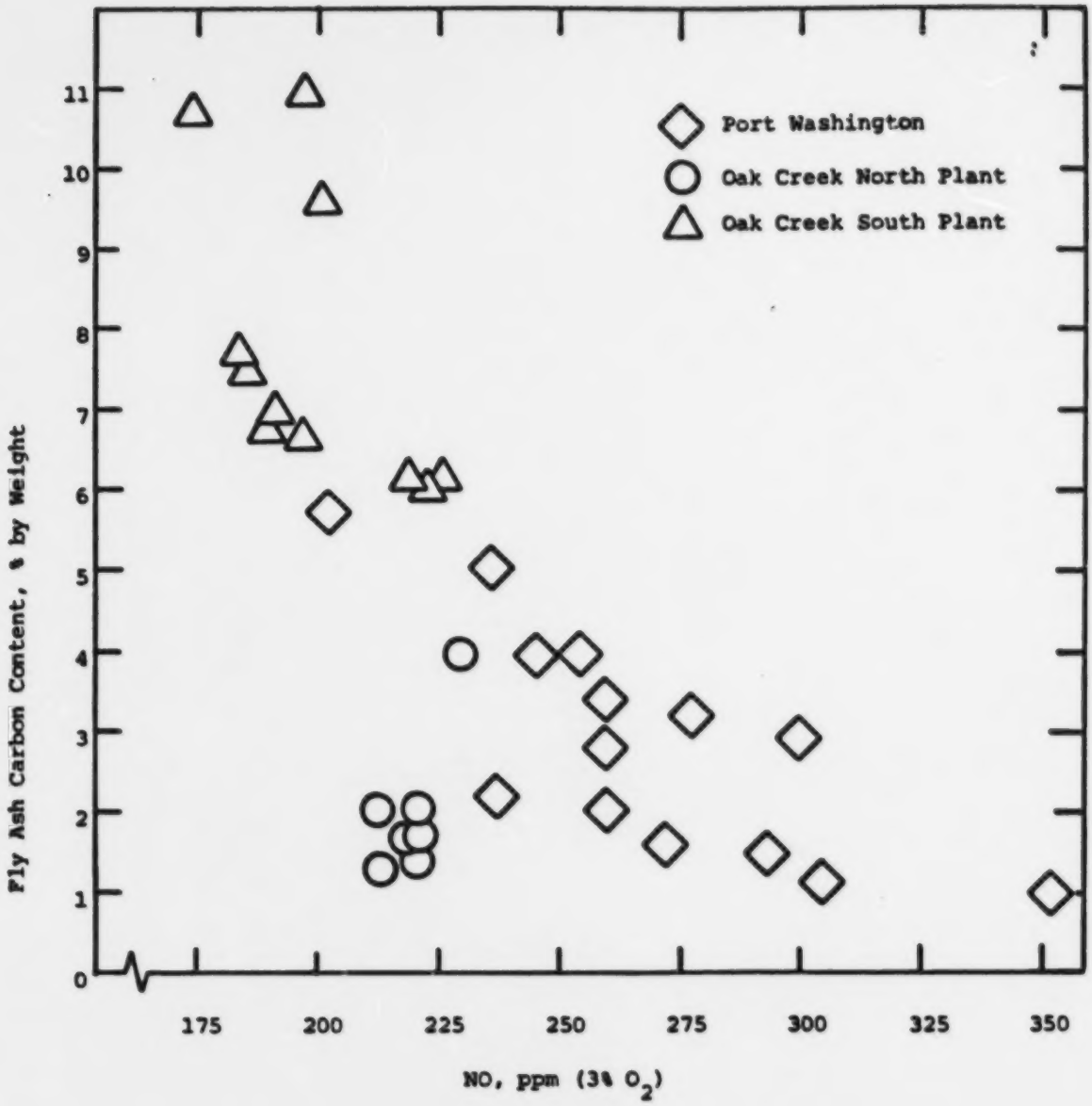


Figure 9. Fly Ash Carbon Content as a Function on NO Emissions, WEPCo Arch-Fired Boilers.

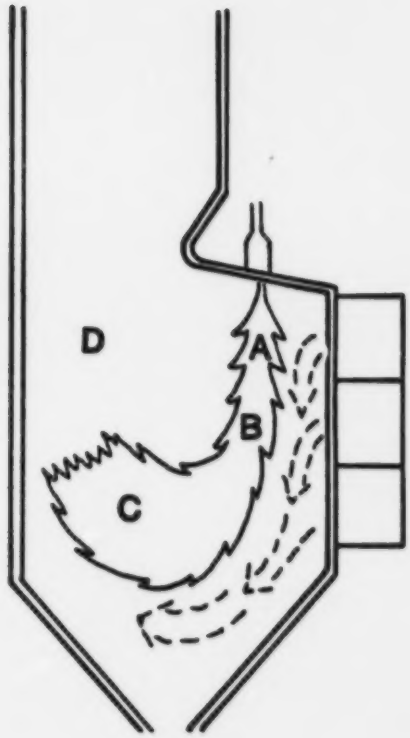


Figure 10. Schematic of Inherent Staged Combustion Process

A Near Burner Region

B Intermediate Stage

C Lower Furnace Region

D Burnout Zone

TABLE I. ARCH-FIRED BOILER OPERATING PARAMETERS
(AT PEAK LOAD DURING TEST CONDITIONS)

	Port Washington	Oak Creek North Plant	Oak Creek South Plant
Load, MW	70.0	125.0	265.0
Steam flow 10^3 lb/hr	520.0	888.0	1780.0
Heat input 10^6 Btu/hr	694.0	1185.0	2293.0
Coal flow 10^3 lb/hr	57.8	98.8	191.0
Total air flow 10^6 ft^3/hr	19.9	32.6	72.0
Primary air flow 10^6 ft^3/hr	1.9	4.4	7.2
Secondary air flow 10^6 ft^3/hr	16.3	28.2	28.2
Tertiary air flow 10^6 ft^3/hr	1.7	--	36.6
Furnace volume 10^3 ft^3	74.0	111.0	171.6
Tube surface area 10^3 ft^2	10.8	17.2	38.3
Number of burners	20	16	16
Burner diameter, in.	6.0	4.5	6.0

TABLE II. AS-FIRED COAL ANALYSES
(Percent by Weight)

	Port Washington Midwestern	Oak Creek North and South Plants Midwestern	Western
Proximate (Wet)			
Moisture	1.40	1.82	2.81
Ash	15.38	14.29	20.70
Volatile	32.37	35.04	37.29
Fixed Carbon	50.85	48.85	39.20
Btu/lb	11,985	11,925	10,318
Ultimate (Dry)			
Carbon	67.99	68.73	60.55
Hydrogen	4.34	4.69	4.55
Nitrogen	1.30	1.46	1.27
Chlorine	0.20	0.30	0.06
Sulfur	3.01	1.72	1.04
Ash	15.60	14.55	21.30
Oxygen	7.56	8.55	11.23

TABLE III. ARCH-FIRED HEAT RELEASE DATA

	80 MW	125 MW	275 MW
Total heat input, Q 10^9 Btu/hr	0.69	1.19	2.29
Total furnace volume, V_F 10^3 ft^3	74.0	111.0	171.6
Q/V_F	9.3	10.7	13.3
Total furnace area, A_F 10^3 ft^2	10.8	17.2	38.3
Q/A_F	63.9	69.2	59.8
Lower Furnace Volume, V_{LF} 10^3 ft^3	36.0	58.5	97.3
Q/V_{LF}	19.2	20.3	23.5
Lower furnace Area, A_{LF} 10^3 ft^2	6.1	10.5	19.5
Q/A_{LF}	113.1	113.3	117.4
Below Arch Volume, V_{BA} 10^3 ft^3	12.5	25.0	46.6
Q/V_{BA}	55.2	47.6	49.1
Below Arch Area, A_{BA} 10^3 ft^2	2.8	6.5	10.0
Q/A_{BA}	246.4	183.1	229.0

COMBINED-CYCLE POWERPLANT EMISSIONS

By:

P. L. Langsjoen, R. E. Thompson, L. J. Muzio
KVB, Inc.
Irvine, California 92714

and

M. W. McElroy
Electric Power Research Institute
Palo Alto, California 94304

ABSTRACT

The retrofit of existing utility steam boilers with a combustion gas turbine to supply hot vitiated combustion air to the windbox of a fired boiler, in place of the normal forced-draft fans and air preheaters (i.e., repowering), can lead to increased power output at improved heat rates. A major consideration in converting to combined-cycle operation is the impact on the nitrogen oxides (NO_x) emissions from the system.

A field test program was conducted to determine the NO_x characteristics of a 220-MW supplementary-fired unit. A primary objective was to determine the fraction of the gas-turbine-generated NO_x that can potentially be reduced upon passage through the combustion zone of the boiler. As part of this test program, the boiler was operated in a low-NO_x, staged-combustion configuration by removing selected burners from service.

Baseline NO_x emissions from the combined-cycle system were found to be substantially lower than NO_x emissions from the boiler alone when operated with ambient air supplied by forced-draft fans: 1.4 lb NO_2/MW-hr compared to 2.3 lb NO_2/MW-hr at boiler loads of 190 MW and 200 MW, respectively. In a staged-combustion configuration with four of twenty burners removed from service, the combined-cycle NO_x emissions were reduced to 0.9 lb NO_2/MW-hr.

The fraction of gas-turbine-generated NO_x reduced upon passage through the combustion zone of the boiler was determined by doping the gas turbine fuel with nitrogen (ammonia) to artificially vary the boiler inlet NO_x levels during combined-cycle operation. The results showed that during normal operation of the combined-cycle system with all burners in service, 10 to 28 percent of the NO_x produced by the gas turbine was reduced (destroyed) in the supplementary fired boiler. During operation of the boiler in a combustion configuration staged by removing four burners from service, a greater portion of the gas-turbine-generated NO_x was reduced in the boiler.

ACKNOWLEDGMENT

This project was sponsored by the Electric Power Reserach Institute (project RD 782) and conducted by KVB, Inc., the Babcock and Wilcox Company, and General Electric Company. KVB, Inc. appreciates the cooperation and efforts extended on the project by the B&W staff (D. Anaki, G. Brechun and E. Campobenedetto), and General Electric.

Also we are very appreciative of the cooperation and technical support of the Oklahoma Gas and Electric Company which provided a combined-cycle unit for testing during this program: Horseshoe Lake Station Unit 7. The station engineering and operating staff at Horseshoe Lake was very helpful in equipment installation, instrumentation, establishment of numerous modified operating modes, net heat rate determinations, control system analysis, and engineering support.

SECTION 1

INTRODUCTION

The retrofit of existing utility steam boilers with a combustion gas turbine to supply hot vitiated combustion air to the windbox of a supplementary-fired boiler in place of the normal forced-draft fans and air preheaters (i.e., repowering), can lead to increased power output at improved heat rates. One of the main considerations in converting to combined-cycle operation is the impact of this modification on the NO_x emissions from the system. The purpose of the study reported in this paper was to assess the NO_x characteristics of a supplementary-fired combined-cycle system and the effectiveness of combustion modifications to the boiler in reducing NO_x emissions.

Prior EPRI-sponsored research projects have indicated that there can be emission as well as efficiency benefits in certain combined-cycle operating modes. Specifically, a combined-cycle system has the potential of operating with substantially lower emissions of NO_x, CO, hydrocarbons, and smoke compared to a gas turbine and a boiler operating separately (1-2) or even compared to a boiler operating with some degree of combustion modifications for NO_x control. In the case of NO_x, the gas turbine exhaust products with reduced oxygen content (approximately 17 percent O_2), supplied to the windbox of the associated boiler, provide some of the benefits that normally would be obtained with flue gas recirculation into the combustion air of a conventionally-fired boiler. This effect would generally outweigh the NO_x disadvantage of higher windbox temperatures encountered in the combined-cycle boiler as compared to a conventional boiler (typically 1000°F compared to 650°F). Thus, the NO_x produced in the boiler of a combined-cycle system will

be less than that produced utilizing a conventional preheated combustion air system. Furthermore, laboratory-scale tests have indicated that the application of two-staged combustion to the boiler could lead to additional NO_x reductions of up to 55 percent from a supplementary-fired combined-cycle system (2). This reduction would be accomplished by operating the burner flame zone of the associated boiler in a low-NO_x staged-combustion mode where local regions in the boiler are operated fuel-rich. The staged combustion mode not only reduces NO_x formed in the boiler but also leads to partial destruction of gas-turbine-generated NO_x as it passes through the fuel-rich region.

Although the repowering concept is very attractive from both a heat rate and emissions standpoint, there has been a lack of full-scale operational data from existing combined-cycle installations to confirm the laboratory-scale results for NO_x control. The application of two-stage combustion is the key element in emissions reduction. Therefore, the principal objective of this test program was to obtain full-scale data to confirm the feasibility of reducing gas-turbine-generated NO_x in the fuel-rich flame of the associated boiler.

Oklahoma Gas & Electric's Horseshoe Lake Plant was selected since the combined-cycle unit at this station has one of the largest supplementary-fired boilers permitting flexibility in establishing low-NO_x operating modes.

During this study, both the gas turbine and boiler were fired with natural gas, due to the unavailability of fuel oil at the time. Although this might be viewed as a shortcoming of this work in light of current utility fuel trends, it is believed that the results may be semi-quantitative for liquid fuels as well.

PROGRAM APPROACH

To accomplish the major program objectives, it was desirable to establish not only the total combined-cycle NO_x emissions with modified combustion modes applied to the boiler, but also to determine the specific reductions in turbine-generated NO_x in the fuel-rich boiler flame zone and the reduction in boiler-generated NO_x. A characterization of the amount of turbine-generated

NO_x reduced in the boiler under varied boiler operating modes and principal test parameters (load, burner air/fuel ratios, etc.) could then be used to predict emissions reductions at other existing or proposed combined-cycle units. It should be noted that these results are for a natural-gas-fired system. Oil fuel NO_x emissions reductions with modified combustion modes more frequently depend on boiler firing configuration than those with natural gas fuel.

An important aspect of the field testing at Horseshoe Lake was to isolate the contributions to the total combined-cycle stack emissions by the boiler and gas turbine. Since gas turbine emissions can be conveniently measured at the boiler windbox inlet, and combined-cycle emissions are readily measured at the stack, a determination of the boiler's contribution to NO_x emissions appears to be the only obstacle to determining the final contribution of the gas turbine to the stack emissions. That is (combined-cycle stack NO_x) - (boiler NO contribution) = (net or final turbine NO_x).

The Horseshoe Lake unit was equipped with back-up forced-draft fans capable of providing full-load boiler combustion air requirements, so it might intially appear that the boiler contribution to total NO_x emissions could conveniently be determined by operating the boiler alone with the FD fans. However, this is not the case for two important reasons: (1) the combustion air temperature would be ambient with only the forced-draft fans instead of 900°F when operating with the gas turbine (boiler air preheaters were not provided); and (2) the unpreheated combustion air would contain 21 percent oxygen instead of the approximately 17 percent oxygen present in the gas turbine exhaust. Both air preheat temperature and combustion air oxygen content (or equivalent gas recirculation rate) are known to have an important influence on NO formation, particularly on gas fuel. Accurate means do not exist to predict the effect of these two variables; hence, calculating the boiler-produced NO_x with combined-cycle operation using the data obtained with forced-draft fan operation was not feasible.

The only practical approach was to preserve the desired boiler inlet preheat and combustion air oxygen content while varying the inlet gas turbine NO, thus generating a plot of stack total NO emissions as a function of gas

turbine inlet NO to the boiler. In this fashion, the boiler contribution to the total combined cycle (stack) NO_x was obtained by extrapolating to a hypothetical condition of zero gas turbine NO_x. This is illustrated in Figure 1.

Because the normal range of turbine operating parameters did not give the desired range of inlet NO_x levels to the boiler, doping the gas turbine fuel with ammonia (NH_3) was selected as a practical way to artificially increase NO_x for purposes of this test. NH_3 reacts with oxygen in the gas turbine combustor, producing N_2, NO_x, and H_2O as the reaction products; in effect, it acts as a fuel nitrogen compound.

The principal boiler operating mode test parameters were load, excess air level, burner air/fuel ratio, and burner firing pattern. The test program was designed to provide answers to the following questions:

- To what degree can combined-cycle NO_x emissions be reduced by implementation of two-stage combustion in the boiler?
- What portion of the NO_x reduction is attributable to reduced NO_x formation in the boiler and what portion is due to destruction of turbine-generated NO_x?
- How dependent is the NO_x reduction on boiler burner firing pattern, excess air level, load, etc., and to what degree are these parameters coupled?
- What potential operational problems, impacts on efficiency, etc., may exist with the implementation of this approach?

A number of limitations in the operating configuration of the boiler were dictated by the gas turbine, which is essentially a constant-volume-flow device with virtually no turndown capability. Because of this the excess-oxygen-versus-load dependence of the boiler is essentially fixed, by the size of the turbine, to provide all the boiler combustion air at full boiler load. At reduced boiler loads, some of the excess combustion air must be directed into the boiler hopper or dumped to the atmosphere.

Although this study is particularly relevant to the repowering of existing gas- and oil-fired plants, there is a wide range of concepts or interpretations of the term "repowering." As we have said, the elementary approach is substitution of a gas turbine for the forced-draft fans so that

the turbine exhaust satisfies the boiler's combustion air requirements are full load. Other considerations, in addition to emissions, are (1) modifications to the windbox to accommodate 900°F+ preheat, (2) additional boiler pressure drop and added heat load in the convective section, (3) physical space for the added gas turbine, and (4) added combustion controls to integrate turbine and boiler firing with accommodations for continued boiler operation with gas turbine loss (3).

A complex approach to repowering is to add gas turbine capacity in excess of that required for the burners in the supplementary-fired boiler, using the boiler convective sections to absorb the extra heat load. This can be accomplished by bypassing the burner regions with a portion of the gas turbine flow and discharging it into the boiler through tempering ports at the top of the radiant or furnace section (3). Other considerations include the ability of the boiler steam circuits to absorb the additional heat load, possible substitution of convective sections, and steam turbine load capacity.

In the more extreme cases of repowering, the boiler may have reached the limits of its serviceable life or it is an inefficient low-pressure, low-reheat design and it is therefore practical to totally replace it with a new waste heat boiler. The existing steam turbine is usually left intact. For these applications, other options must be evaluated: whether the boiler should be supplementary-fired and what power split is most efficient between the gas turbine and the steam turbine output. These are the considerations involved in new combined-cycle unit design; frequently it is more effective not to fire the new boiler. The reader is referred to EPRI Report FP-862 (3) for a more detailed discussion of these considerations from the efficiency and emissions standpoints. Other considerations are existing steam turbine capacity, unit maintenance and life cycle costs, and lost generation during repowering construction.

This paper deals with the current combined-cycle system at Oklahoma Gas and Electric, Horseshoe Lake Station, which was designed so that the turbine exhaust provides all the boiler combustion air. Therefore, these results are directly applicable to the elementary repowering approach of direct substitution for the forced-draft fans. With some caution in interpretation, these

results could also be applied to the case of additional gas turbine bypass into the upper furnace region as long as this flow does not influence boiler combustion conditions or emissions.

The final configuration already discussed requires repowering with a new unfired waste heat boiler and thus does not directly relate to the combined-cycle configuration tested during this program. Emissions are directly dependent on the most recent advances in gas turbine combustor design. Nor will these results be directly applicable to repowering situations where duct burners are used to heat the gas turbine exhaust only 100 to 300°F. In this latter case, the duct burner fuel combustion consumes only a minimal amount of the oxygen in the gas turbine exhaust, with the majority of the gas turbine flow effectively bypassing the burners.

SECTION 2

COMBINED-CYCLE SYSTEM DESCRIPTION

Oklahoma Gas & Electric's Unit No. 7, placed in service in 1963, is a 220-MW combined-cycle system incorporating a General Electric frame 8 gas turbine and a front-wall-fired Babcock & Wilcox boiler with the following general characteristics:

Gas turbine:	Maximum output 25 MW
Boiler:	Maximum continuous steam flow 1,286,000 lb/hr Maximum continuous output 205 MW gross
Combined cycle:	Heat rate 9629 Btu/kW-hr (at 219.3 MW net station output, natural gas fired)

The gas turbine exhaust normally provides all the oxidizer to the boiler. Two forced-draft fans furnish combustion air to the boiler when the gas turbine is not operating. Under normal operation, these fans also supplement the turbine exhaust from the most economical load of approximately 1,145,000 lb steam/hr to the top load of 1,339,000 lb steam/hr. No air preheating, other than turbine exhaust, is provided for the boiler; ambient-temperature air is used for combustion when the gas turbine is out of service.

A large economizer instead of an air preheater lowers the stack temperature to nominally 321°F. With the gas turbine operating, all of its exhaust must either pass through the burner region or the furnace hopper bottom. (Gas tempering ports to bypass turbine exhaust to the boiler convective section were not in service, and a turbine startup bypass duct to the atmosphere was not sufficient to handle the full turbine exhaust flow.)

GAS TURBINE SYSTEM

The gas turbine generator is a General Electric Company frame 8 two-shaft turbine rated at 25,000 kW with an 80°F compressor inlet temperature and 14.17 psia at the compressor inlet and turbine exhaust flange. At rated conditions, the high-pressure turbine (which drives the compressor) turns at approximately 3285 rpm. Gas temperature at the inlet to the first-stage nozzles is 1500°F; the exhaust temperature is 870°F. This gas turbine unit has no provisions for NO_x control.

Control of the gas turbine fuel flow is dictated by control of the exhaust gas temperature within specified limits. The control system is such that, if ambient conditions change, the electrical load from the gas turbine generator will change since the gas turbine compressor, running at constant speed, will pump a constant volume, but not constant weight or air.

No other means is employed to vary the steam generator excess air. The gas turbine output depends on ambient temperature only. Air tempering dampers installed with the unit to permit turbine exhaust bypass to the boiler convective section are not in use, and a bypass duct which diverts the turbine exhaust to a separate stack is used only for startup.

BOILER SYSTEM

The steam generator is a front-wall-fired Babcock & Wilcox radiant-type boiler with a nominal rated steam flow of 1,286,000 lb/hr (205 MW). The physical configuration of the combined cycle unit is shown in Figure 2. The pressurized furnace is normally fired with natural gas fuel, with oil on standby. The 20 center-fire Laredo-type burners are arranged in a four-wide by five-high pattern as shown in Figure 3. Steam temperature control is by means of spray attemperation and flue gas recirculation into the hopper bottom of the furnace. Outlet superheat and reheat steam temperatures are 1005°F and 1005°F, respectively.

Over most of the combined-cycle load range, the gas turbine supplies all the combustion air for the steam generator. However, combustion air is supplemented by forced-draft fans at boiler loads about 180 MW, depending on

the ambient temperature. At steam turbine gross loads below about 150 MW, the excess air level at the burners becomes excessively high. When this occurs, dampers are opened to divert some of the gas turbine exhaust into the bottom hopper of the boiler, reducing the O_2/fuel ratio through the burners.

AMMONIA INJECTION SYSTEM

A system was devised for injecting ammonia (NH_3) into the fuel (not the exhaust) system of the gas turbine so that the turbine exhaust NO_x level could be varied from approximately 50 to 100 ppm (dry at 15 percent O_2). The NH_3 reacted in the gas turbine flame to form NO_x, N_2, and H_2O, greatly increasing the total NO_x output when injected in small concentrations. The limit of 100 ppm was chosen since in a prior laboratory study (2) it had been shown that the gas turbine reduction factor was independent of the initial NO_x level up to 100 ppm, and data were not available to confirm the independent relationship at levels much greater than 100 ppm. The ammonia was sprayed as a liquid upstream against the direction of the natural gas flow at a point just after the gas line control valve and just prior to a "T" in the line which carried the gas to either side of the circular gas header to the combustor cans. Subsequent evaporation of the maximum NH_3 flow in the fuel supply line would cool the natural gas by 5°F at most.

GASEOUS EMISSIONS SAMPLING SYSTEM

Boiler flue gas was sampled at the stack with six three-point probes. Multi-point water-filled gas bubblers were used to obtain a composite flue gas sample. The flue gas was drawn into the bubbler with an air aspirator. The gas was analyzed with a Dynascience NO_x analyzer, Beckman O_2 and CO analyzers, and an Orsat analyzer.

The gas turbine exhaust was sampled at the turbine outlet just before it divides to supply the north and south sides of the boiler. Nine probes were installed in the turbine exhaust duct. NO/NO_x measurements at the turbine exhaust were made with a Thermo-Electron chemiluminescent analyzer. Other gaseous measurements were made with the following analyzers: Teledyne

Model 326A, O_2; Horiba Model A1A-21 NDIR, CO_2; and Beckman Model 315A NDIR, CO.

SYSTEM TEST CONFIGURATIONS

The test program comprised a series of tests over a wide range of system configurations. This included both combined-cycle and single cycle operation (forced-draft fans only, no preheat). Staged combustion was also investigated on both basic configurations. Table I outlines the system configurations and range of variables investigated.

A more extensive test program was initially planned than is outlined in Table I to investigate boiler performance and emissions over a wider range of load and firing configurations. Unfortunately, the difficulties encountered in gas turbine firing rate control with NH_3 injected into the fuel could not be resolved, and the extent of the resulting test data, although sufficient to accomplish major project objectives, is considerably less than what was initially desired for a thorough study of the topic.

DATA REDUCTION

Before discussing data reduction methods it is appropriate to briefly reiterate the basis for which emissions reductions for combined-cycle systems are being calculated. We are concerned with NO_x emissions control or NO_x reduction potential, so it is important to establish the conventional baseline operating configurations to which the reduced emissions operating mode is being compared.

There are two basic measure of interest in combined-cycle emissions in the current study:

1. Reduction in total stack emissions by implementing staged combustion in the boiler using as-found combined-cycle emissions as a baseline.

2. Reduction in gas turbine emissions by the more fuel-rich boiler flame zone; judged by comparison to the initial gas turbine exhaust NO_x level.

The latter gas turbine NO_x reduction potential can be expressed as:

$$r = 1 - \left[\frac{\dot{M}_{NO_x\,stack} - \dot{M}_{NO_x\,boiler}}{\dot{M}_{NO_x\,gas\ turbine}} \right]$$

where:

r = fraction of oxides of nitrogen produced in the gas turbine which is destroyed in passing thorough the boiler

$\dot{M}_{NO_x\,stack}$ = mass emission rate of oxides of nitrogen in the combined cycle exhaust products (lb/hr)

$\dot{M}_{NO_x\,boiler}$ = mass emission rate of oxides of nitrogen produced by the boiler while fired with gas turbine exhaust with no inlet nitric oxide (lb/hr)

$\dot{M}_{NO_x\,turbine}$ = mass emission rate of oxides of nitrogen from the gas turbine (lb/hr).

The interrelationship of these terms is shown in Figure 4.

A clear distinction should be made of the basis upon which the combined-cycle system emissions are compared. This requires that boiler operating conditions be clearly stated:

(a) The emissions from a boiler operating normally without flue gas recirculation but with preheated combustion air (21 percent O_2, approximately 600°F).

(b) The emissions from a boiler operating without flue gas recirculation but with combustion air at ambient temperature (21 percent O_2, approximately 70°F).

(c) The hypothetical emissions from a boiler operating on gas turbine exhaust that has all the normal characteristics except zero NO_x content (approximately 17 percent O_2 and 900°F).

Case (a) above would be of interest as representative of the current emissions of a boiler being considered as a candidate for "repowering."

Case (b) is unlikely to be encountered in normal utility practice but is of interest in terms of plant emissions when the gas turbine is out of service. It also was investigated during the current program as an operating configuration that would provide more insight into the emissions reduction potential of low NO_x firing modes in the boiler.

Case (c) is the hypothetical condition necessary to calculate the gas turbine NO_x reduction factor as indicated in the previous equation. It is desirable to isolate the effect of the boiler flame zone conditions on the destruction of the turbine exhaust NO_x from the overall unit NO emissions so that the results of this study can be generalized to other combinations of turbine and boiler NO_x. Otherwise, the study conclusions would be applicable only to repowering cases having similar boiler and candidate gas turbine emissions.

This raises the subject, touched on previously, of the possible dependence of the NO_x reduction factor on the gas turbine exit or boiler inlet NO_x level. The subscale laboratory study (1-2) showed that the NO_x reduction factor (r) was not a function of the NO_x levels in the gas turbine exhaust, at least up to concentrations of 100 ppm (at 15 percent O_2). Data were not available to assess whether or not the reduction factor was independent of the boiler inlet NO_x levels above 100 ppm. Based on the assumption that the reduction factor is independent of inlet NO_x level, the resulting nitric oxide emissions from the combined cycle would plot linearly versus gas turbine NO and could be linearly extrapolated to a condition of zero NO_x in the gas turbine exhaust, thus determining boiler-produced NO_x. This approach was followed in the reduction of Horseshoe Lake field test data and indeed did confirm the assumption that the reduction factor is independent of gas turbine NO_x concentration.

The primary step in the data reduction procedure was the calculation of the gas turbine NO_x reduction factor. To do this it was necessary to express all oxides of nitrogen emissions on a mass flow (lb/hr) basis. Other quantities which were calculated from the measured parameters include the gas

turbine and boiler air/fuel ratios (or stoichiometric ratios), and the approximate stoichiometric ratios at the burners while operating in a staged combustion configuration. The resulting data of stack NO_x versus gas turbine NO_x was plotted and the data extrapolated to zero gas turbine NO_x.

This plot of stack NO_x versus gas turbine NO_x for a typical test condition is shown in Figure 5. For this particular case the tests show that the boiler would have produced 115 lb/hr of oxides of nitrogen if it had been fired with gas turbine exhaust with no NO_x present (intercept). Also, the test results indicate that for this configuration, 49 percent of the oxides of nitrogen produced in the gas turbine were destroyed upon passing through the supplementary-fired boiler (i.e., r = 49 percent).

SECTION 3

TEST RESULTS AND INTERPRETATION

BOILER-ONLY TESTS

The boiler-only tests provide an understanding of the responsiveness of the unit to load variations, changes in excess oxygen, and burner-out-of-service patterns for low NO_x emissions. Performing these tests with the forced-draft fans prevents problems in data interpretation introduced by the gas turbine and allows an assessment of the boiler's behavior. These tests were also conducted to select an effective pattern of burners out of service to be used during the combined-cycle tests. Finally, the data obtained when the boiler was operated with only the forced-draft fans provided a common basis of comparison with the combined-cycle emissions. As previously mentioned, this does not allow a totally valid comparison with normal utility boiler operation as the combustion air is not preheated in this unit when operating with the forced-draft fans. Since NO_x formation, particularly for natural gas firing, is a direct function of the combustion temperatures and air preheat, the NO_x emissions for the boiler-only tests with no air preheat are expected to be lower than would be emitted from a unit with combustion air preheated (nominally 600°F).

The sensitivity of the NO_x emissions to excess oxygen levels and load for single-stage (ABIS: all burners in service) and staged combustion (BOOS: burners out of service) is shown in Figure 6. At a load of 169 MW, increasing the stack O_2 level from 2 to 4 percent resulted in an 8 percent increase in NO levels. At the lower load of 130 MW, the unit exhibited little sensitivity to excess oxygen changes with only a 4 ppm increase in NO_x as the O_2 level in the stack was increased from 3.9 to 5.0 percent. If the unit had been operated

with the combustion air preheated to 600°F, it is estimated that boiler emissions could be two to three times higher than measured during this program with ambient temperature combustion air.

Staged combustion was implemented by removing burners from service. This entailed terminating the fuel flow to selected burners while maintaining load, resulting in an increase in fuel flow to the remaining in-service burners. The nominal air flow was maintained through the out-of-service burners (registers open). Staged combustion tests were conducted with forced-draft fan operation to determine the overall sensitivity of the unit to staging and identify the burner patterns to be used during the combined-cycle tests. Again, during these tests, the boiler overall excess air level was maintained at the same level as in the normal all-burners-in-service operating mode, and the minimum excess air limit was not determined for each burner pattern tested. During combined-cycle operation, the stack O_2 level was determined by the power split between the gas turbine and supplementary-fired boiler and was not at the discretion of the operator. These test results are summarized in Table II.

In performing these tests, burner air registers were open to their normal open position (60 to 70 percent) whenever burners were taken out of service. The burner pattern testing focused on removing burners from the top two rows, either the entire row--13, 14, 15, 16; 17, 18, 19, and 20--or the two middle burners of each row--14, 15 or 18, 19. (See Figure 3 for the burner numbering system.) Previous studies (4) have shown that removing burners from the upper rows is more effective in reducing NO_x than removing bottom rows of burners, but it was beyond the scope of the present program to explore all possible burner patterns for this unit. This is consistent with the objectives of the program in investigating the combined-cycle NO_x emission reduction potential (in particular the reduction of the gas-turbine-generated NO_x through staged combustion in the boiler). Since time was insufficient to explore the NO_x reduction potential of all burner patterns, a burner pattern was sought that resulted in NO_x reductions that were typical (not necessarily optimum) of previous experience with gas-fired utility boilers. Further, it is not currently known whether a burner pattern which produces minimum NO_x with

forced-draft fan operation necessarily results in the largest reduction in gas-turbine-generated NO_x. Previously reported laboratory studies (1-2) indicate that the gas turbine NO_x reduction increases as the stoichiometric ratio of the in-service burners decreases.

Removing the middle burners of a row from service (14, 15) resulted in a NO_x reduction of 25 percent at a load of 169 MW (Test 15). When the middle burners of the top row (18, 19) were removed from service, the NO_x reduction was only 2 percent (Test 3); these tests were conducted at a higher overall boiler excess air level. Based on the NO_x-versus-O_2 characteristic shown in Figure 6, the differences in the excess O_2 level may have accounted for 25 ppm or 14 percent of the reduction.

When four burners were removed from service, the NO_x reductions obtained were not highly dependent on whether the top row or second row was removed. At a load of 169 MW and nominal stack O_2 level of 4 percent, a 22 percent reduction in NO_x was measured with the top row out of service and 24 percent reduction in NO_x with the second row from the top removed from service. When reducing the stack O_2 level to 2.25 percent at 168 MW (Test 14) the NO_x reductions increased to 43 percent with the second row from the top out of service (13, 14, 15, 16).

Because removing from service either two burners or four burners of the second row from the top resulted in NO_x reductions typical of those achieved in other gas-fired utility boilers, this pattern was selected for use during the combined-cycle tests.

COMBINED-CYCLE TEST RESULTS

The primary objectives of the combined-cycle tests were to evaluate the potential for destroying a portion of the NO_x generated in the gas turbine and to determine the relationship between this destruction process and the boiler operating configuration. The boiler configurations evaluated included:

- Baseline operation (all burners in service).
- Staged operation (burners 13, 14, 15, and 16 out of service).
- Low load, with turbine exhaust bypass through the ash hopper.

The results of these tests are summarized in Table III. Each test series represents a fixed turbine operating condition and set boiler configuration (i.e., excess O_2, load, burner pattern). For each test series a number of tests were conducted. The different test numbers in a series vary only the gas turbine exhaust NO_x level by varying the NH_3 injected into the gas turbine fuel. In the table the gas turbine emissions and combined-cycle stack emissions are reported for conditions with no ammonia doping of the gas turbine fuel.

Although a number of different boiler operating configurations were tested to characterize the NO_x destruction in the boiler flame, the gas turbine was operated at relatively constant conditions throughout the test series.

In analyzing combined-cycle test results, the following aspects need to be assessed:

- Stack NO_x emissions rate and the effect of operating conditions.
- Boiler contribution to the stack NO_x emission rates.
- Gas turbine reduction factor.

First, consider the stack NO_x emissions from the combined cycle. For normal combined-cycle operations, the stack NO_x emission rates were substantially lower than those when the boiler was operated with only the forced-draft fans. For example, comparing Tests 17 and 47 indicates that at a boiler load of about 200 MW the combined cycle emits 305 lb/hr of NO_x (as NO_2) whereas single-cycle operation with the forced-draft fans yielded stack NO_x emissions of 467 lb/hr. Combined-cycle emissions are 35 percent lower, even when compared to operation with cold boiler air.

NO_x emissions from the combined cycle are substantially lower if they are normalized on a unit load basis as shown in Table IV and Figure 7a. In Table IV and Figure 7a, the emissions are normalized by the load of the specific device. Thus, for single-cycle operation, the boiler emissions are normalized by the boiler load, the gas turbine by the gas turbine load and,

for combined-cycle operation, the emissions are normalized by the combined-cycle load (boiler plus gas turbine).

NO_x emissions are plotted on a mass-emission-rate basis in Figure 7b, illustrating an interesting comparison to the NO_x emissions normalized on an output-load basis. First, it can be seen that for single-cycle operation, the mass emission rate from the gas turbine was substantially less than the NO_x emission rate from the boiler. Second, the emissions reduction with combined-cycle operation compared to single-cycle operation was primarily due to a reduction in the emissions from the boiler. Finally, with staged-combustion operation of the combined cycle (4 BOOS), the NO_x emissions were reduced by 36 percent compared to combined-cycle operation with all burners in service. This 36 percent NO_x reduction was a result of a 40 percent reduction in the boiler emissions and a 27 percent reduction in the NO_x contribution from the gas turbine. Thus, even though a substantial fraction of the gas-turbine-generated NO_x was destroyed in the boiler, the overall NO_x reduction from combined cycle operation with the implementation of staged combustion was primarily due to reductions in the NO_x contribution from the boiler.

It should be noted that the single-cycle emissions in Table II were obtained at an excess oxygen level approximately 1 percent higher than the combined cycle operating mode. Even if the results were normalized to a common O_2 level, this would reduce the single-cycle emissions by about 10 percent, indicating that the combined-cycle emissions are still substantially lower.

For normal operation of a typical natural-gas-fired utility boiler, the NO_x emissions were estimated to be up to two to three times higher than the 2.3 lb NO_2/MW-hr tabulated in Table IV due to the use of combustion air preheat, which was not used in this case.

Similar comparisons can be made at other loads from Tables II and III, with similar conclusions. Two factors affected the NO_x emissions from the combined-cycle configurations, in addition to the fact that the oxidizer stream (gas turbine exhaust) contained NO_x. The primary factor was the presence of combustion products in the oxidizer stream (CO_2 and H_2O) which

acted as inerts and reduced the oxygen concentration in the boiler oxidizer flow to 16.6 percent O_2 compared to 21 percent. This was equivalent to approximately 26 percent flue gas recirculation. The diluent effect resulted in reduced flame temperatures and lower NO_x formation in the boiler, similar to flue gas recirculation. Second, counteracting this effect was a gas turbine exhaust temperature of 800°F, whereas with the forced-draft fans the air was at ambient temperature. However, the results suggest that the effect of preheat temperature was less compared to the reduced oxygen content. This may not be the case for an oil-fired unit with high fuel nitrogen content as it is generally known that flue gas recirculation with high nitrogen fuels (e.g., residual oil) is less effective than with natural gas fuel.

Next consider the effect of a staged boiler operating configuration on stack NO_x emissions from the combined-cycle operation. At the high boiler load condition (190 to 198 MW), removing four burners from service resulted in a 36 percent reduction in NO_x emissions. It should also be noted that the boiler O_2 dropped to 1.9 percent during the tests with four burners out of service at a load of 198 MW compared to the baseline O_2, which was in the range of about 2.7 percent at 190 MW. This should result in a further NO_x reduction beyond just removing the four burners from service at the same O_2 level, as indicated in the general behavior of the unit with excess air (forced-draft fan operation) as depicted in Figure 6. Thus the 36 percent NO_x reduction was due to both removing four burners from service and reducing the O_2 level from 2.7 to 1.9 percent. It was not possible to independently control the overall boiler O_2 and the load during the combined-cycle operation and thus establish the relationship between boiler excess O_2 and combined-cycle NO_x emissions at a fixed load. This limitation exists because the gas turbine is essentially operated at a fixed condition with all of the combustion products fed to the boiler. The boiler load, or fuel flow, determined the flue gas oxygen concentration.

At the lower boiler load (150 MW) the stack NO emissions were not altered by removing four burners from service (compare Tests 27-29 and 33-34). A major contributing factor appears to be the unexpected increase in boiler-produced NO accompanying staged combustion. Although no clearcut

explanation can be offered for this, as it is contrary to the behavior with the forced-draft fan operation, the excess oxygen level was high (6.2 percent) during these combined-cycle tests. So, even with four burners out of service, the in-service burners were still operating with excess oxygen.

During Tests 30-32, an attempt was made during combined-cycle operation to lower the air/fuel ratio at the burners by diverting a portion of the gas turbine exhaust away from the burners and adding it through the bottom hopper as the only available means to simulate low-excess-air operation at the burners. As seen in Table III, this resulted in a 28 percent increase in NO_x emissions. In actuality, this configuration did not simulate low-excess-air operation as visual observation showed that the bypass flow through the hopper flowed up the furnace walls into the burner region. This appears to have resulted in enhanced mixing with the burner flow, producing more intense flames. This in turn resulted in higher NO_x formation in the boiler; none of the gas-turbine-produced NO_x was destroyed with this configuration.

Next consider the reduction of the gas-turbine-generated NO_x which occurred in the boiler. The test results for normal and low NO_x combined-cycle operating modes showed that from 10 to 49 percent of the NO_x generated in the gas turbine was destroyed upon passage through the boiler. The specific reduction factors are tabulated as (r) in Table III. At a boiler load of 150 MW, the reduction factor increased from 10 to 27 percent when four burners were removed from service. However, it can be noted in Table III that while the reduction factor increased, the boiler-produced NO_x apparently increased, resulting in no change in the stack NO_x emission rate. No definitive explanation of this result is presently available. As discussed above, with bypass through the ash hopper to simulate low-excess-air operation at the burners, none of the gas turbine NO_x was destroyed in the boiler.

The reduction factors measured at the higher load conditions (188 to 198 MW, baseline) exhibited a similar trend. During Tests 27 and 28 with all burners in service, the test results indicated that 28 percent of the turbine NO_x was destroyed. With four burners out of service, the reduction factor was determined to be 49 percent. This, coupled with a 40 percent reduction in the boiler-generated NO_x as a result of the staged combustion mode, produced the

overall 36 percent reduction in stack NO_x emissions. It should be noted that between Tests 37-38 and 23-26 there was a decrease in excess O_2, tending to lower the NO_x emissions, and a slight increase in load, tending to offset the reduction.

The previous laboratory studies (1-2) showed that the gas turbine NO_x reduction factor, r, was a function of the equivalence ratio (i.e., the reciprocal of the stoichiometric ratio, $\Phi_b = 1/SR_b$) of the in-service burners. Thus as the in-service burners were made to operate more fuel-rich (higher Φ_b), (r) increased. For the test series tabulated in Table III, the approximate in-service burner equivalence ratio Φ_b was calculated. The resulting relationship between the NO_x reduction factor and the in-service burner equivalence ratio is shown in Figure 8.

The data plotted in Figure 8 include both high and low load as well as as all-burners-out-of-service test configurations. The relationship appears to be linear with a correlation coefficient of 0.99 for a least squares linear fit. However, the number of data points is limited, and further data are needed to substantiate the relationship.

GENERALIZATION OF TEST RESULTS

The test results have generally shown that (1) combined-cycle NO_x emissions are less than single-cycle emissions and (2) a substantial portion of turbine-generated NO_x can be destroyed in the boiler. The extent to which these results can be treated as "general" warrants discussion.

The extent to which the combined-cycle emissions are lower than normal will be dependent on the function of the power split of the combined-cycle system. For these tests approximately 27 percent of the fuel is burned in the gas turbine. As lower-heat-rate turbines come into use, less fuel will be burned in the boiler; this will affect both the NO_x formed in the boiler and the reduction of turbine-generated NO_x. In fact, the most thermally efficient combined-cycle system is comprised of a gas turbine and unfired waste heat boiler. The emission characteristics of this system will be greatly different from the unit tested during this program.

Bypassing a portion of the gas turbine exhaust to the ash hopper produced interesting and unexpected results. Operational situations can exist at low load where bypassing a portion of the gas turbine exhaust from the burners is desirable. One might be inclined to conclude that the NO_x emissions should fall. Instead, these tests results indicated that bypassing the gas turbine exhaust to the ash hopper yielded more intensely mixed flames, producing higher NO_x. A more successful approach might be to divert the flow and inject it in a region above the burners, avoiding mixing of the bypass with the burner flow.

Also worthy of discussion is the method of implementing staged combustion for low NO_x operation. In this study burners were removed from service and the fuel diverted to in-service burners to create fuel-rich regions. With this configuration, the portion of the gas turbine exhaust which passes through the out-of-service burners does not directly pass through a fuel-rich flame. One might anticipate that this portion of the gas-turbine-generated NO_x cannot be reduced, limiting the reduction factor. This turns out not to be the case. In reported small-scale tests (2), it was shown that not only was the NO_x reduced in the portion of the gas turbine stream fed directly to a fuel-rich burner, but also a portion of the NO_x in the staged oxidizer flow that bypassed the burner was also reduced. It was not possible to quantify the relative portion representing the fraction of the NO_x destroyed passing through the fuel-rich region and the fraction reduced as the staged air is mixed with the fuel-rich stream. Reduction factor (r) reported in (2) represents the total reduction of the gas turbine NO_x and is thus directly comparable to the reduction factor calculated in this study (i.e., the reduction factor is not apportioned to the fuel through the burner and that which is bypassed as staged air).

A similar situation will probably exist with low NO_x burners that may be available in future new installations. These low NO_x burners will more than likely achieve reduced NO_x by aerodynamically staging the flame at the burner rather than staging the entire furnace, as occurs with burners-out-of-service operation. Since the low NO_x burners use a form of staging with probably comparable boiler NO_x levels, it is reasonable to anticipate a reduction in

gas-turbine-generated NO_x using low NO_x burners in combined-cycle systems. However, data are not available to quantify these anticipated reductions relative to the results with burners out of service tested during this study.

A final note of caution is appropriate in the use of gas turbine and boiler emissions data obtained during this program. As with all combustion equipment NO_x emissions, they are design type, fuel type, operating mode, and site specific. Therefore, one should use considerable care in applying the data obtained during this test series to predict emissions from future potential repowering candidates. This is particularly true because the General Electric frame 8 two-shaft gas turbine is not a recent design and is not completely representative of recent gas turbine emission factors for NO_x. Although the data here can be effectively used in a proportional NO_x reduction manner for comparative purposes in evaluating operating modes, its use in an absolute sense for emissions forecasting is ill advised.

Additionally it must be noted that this study was conducted with a natural-gas-fired system (both turbine and boiler). Current interest focuses on oil-fired systems. A note of caution is thus offered in extrapolating these natural-gas-fired results to oil firing.

REFERENCES

1. Hunter, S.C., "Combined Cycle NO_x Study," final report, EPRI report 224-1, Volume I, February, 1975.

2. Arand, J.K., "Reduction of NO Through Staged Combustion in Combined Cycle Supplemental Boilers," EPRI report 224-1, Volumes II and III, February, 1975.

3. Foster-Pegg, R.W., "Combustion Turbine Repowering of Reheat Steam Power Plants," EPRI Rpoert FP-862, August, 1978 (final report of research project 528-1, Westinghouse Electric Corporation.)

4. McGuire, W.G. et al., "Theory and Application of Nitric Oxide Emission Reduction in Utility Boilers," presented at the First Annual Symposium on Air Pollution Control in the Southwest, Texas A&M University, November, 1973.

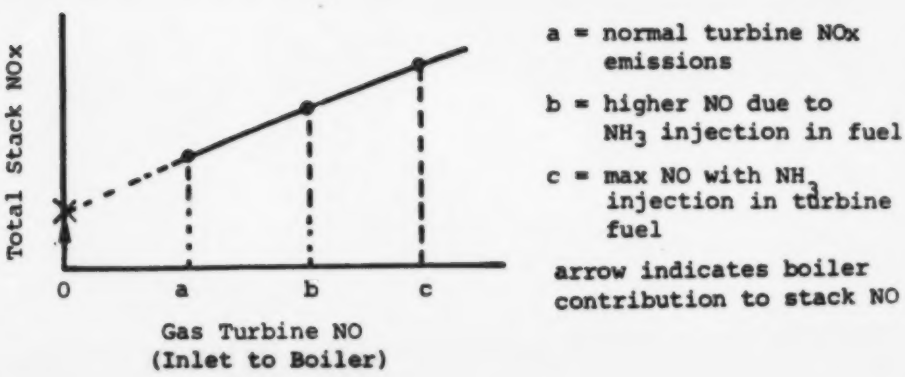


Figure 1. Sketch of stack NOx levels versus gas turbine NO levels

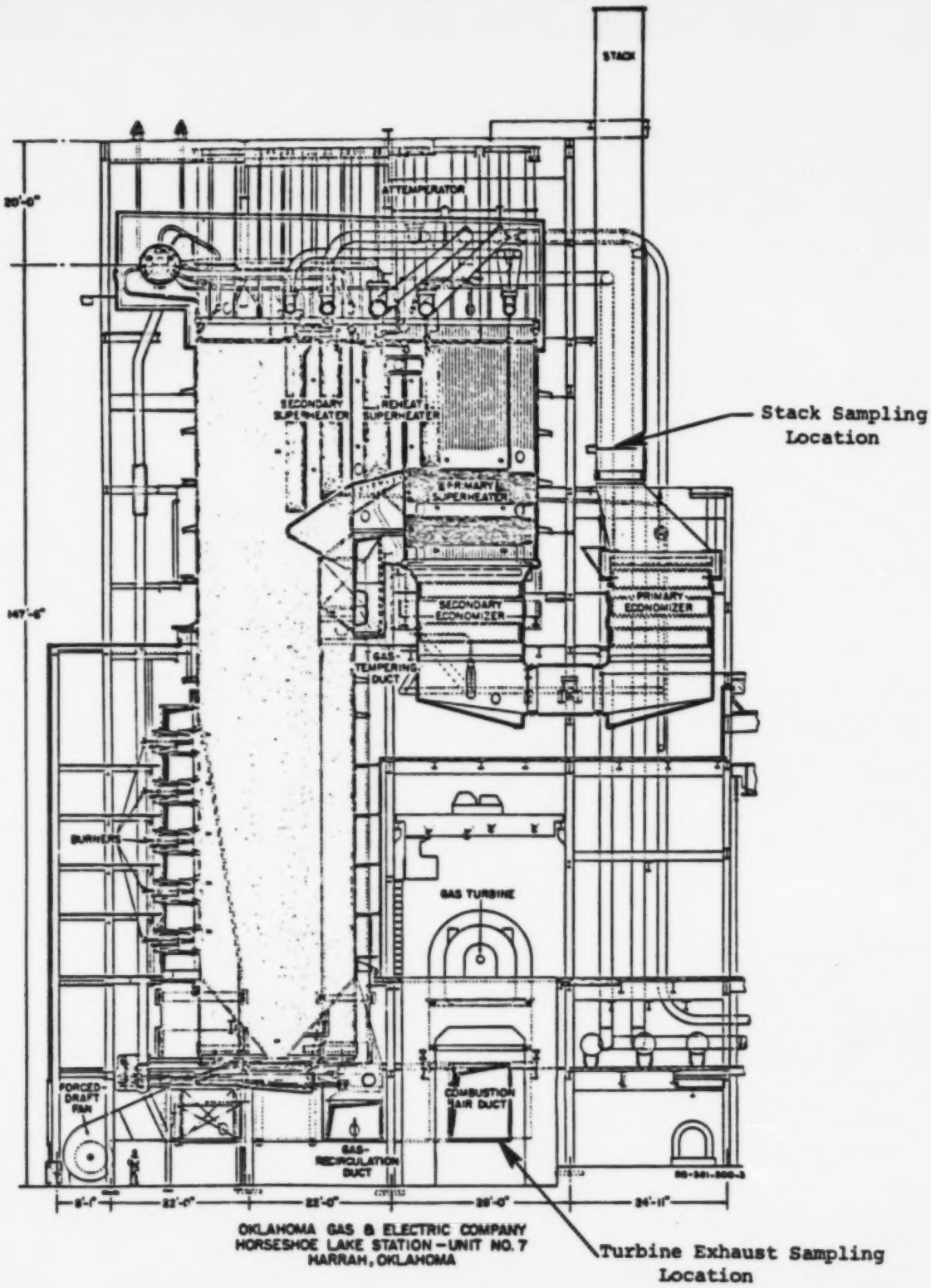


Figure 2. Physical configuration of OG&E Unit No. 7

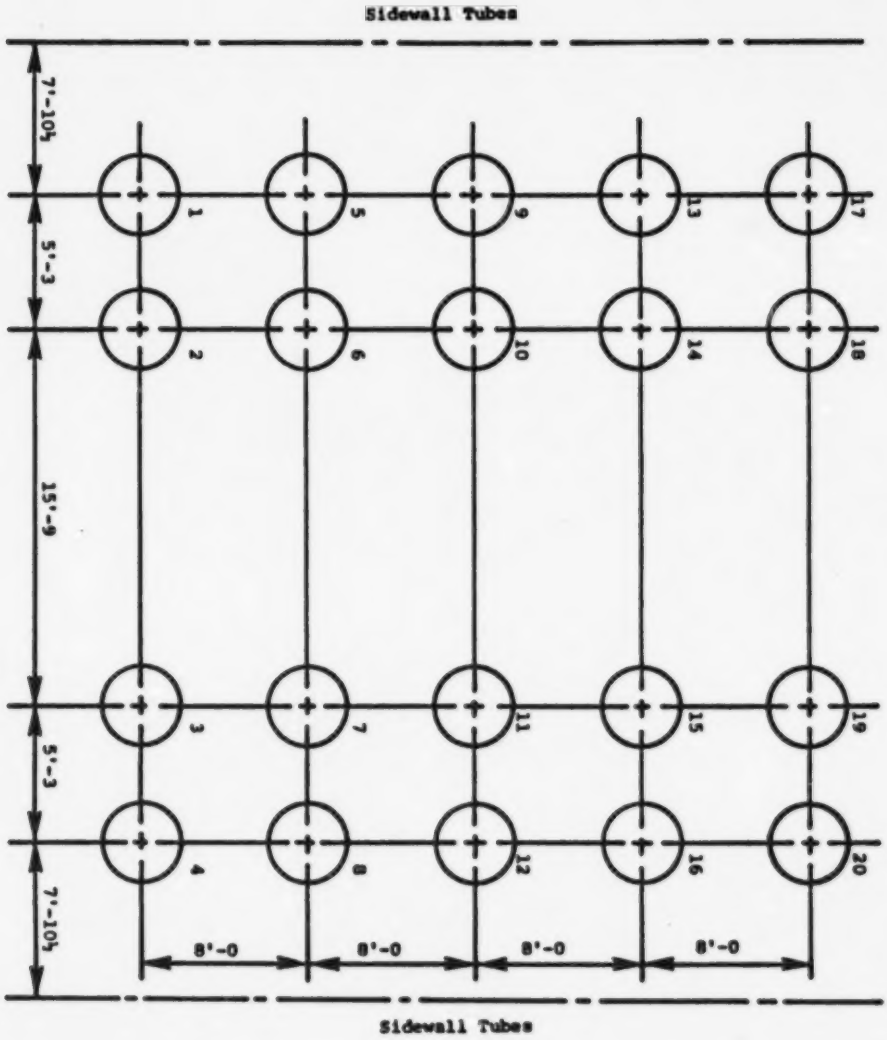


Figure 3. Arrangement of burners in the steam generator

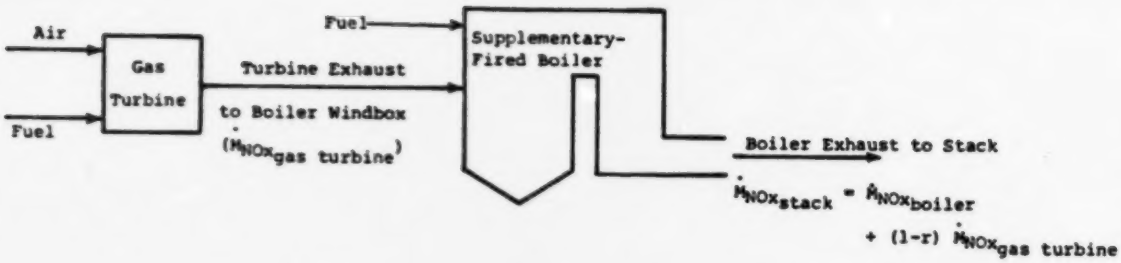


Figure 4. Sketch of the NOx contributions for the combined-cycle system

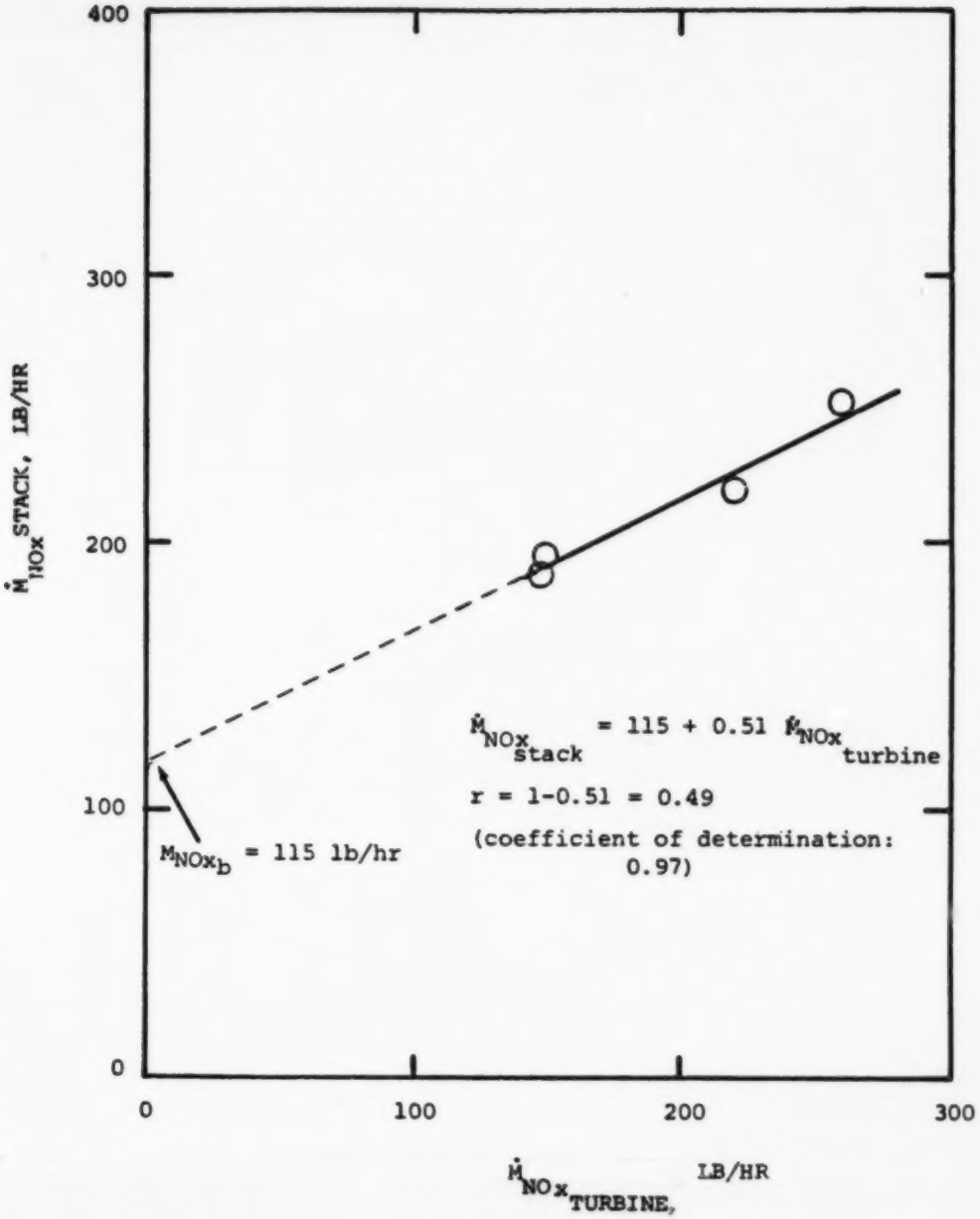


Figure 5. Typical combined-cycle stack NOx versus gas turbine NOx

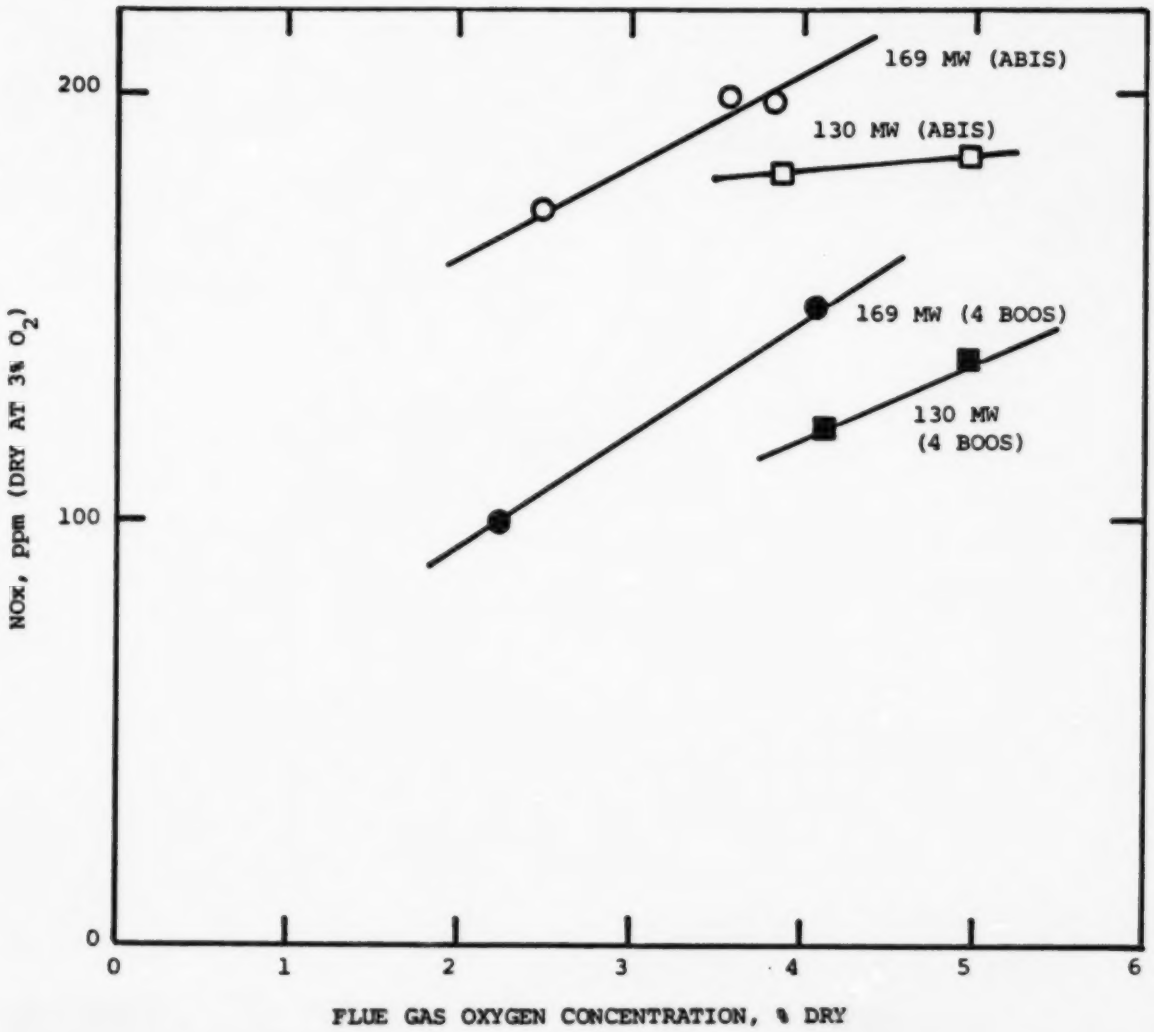
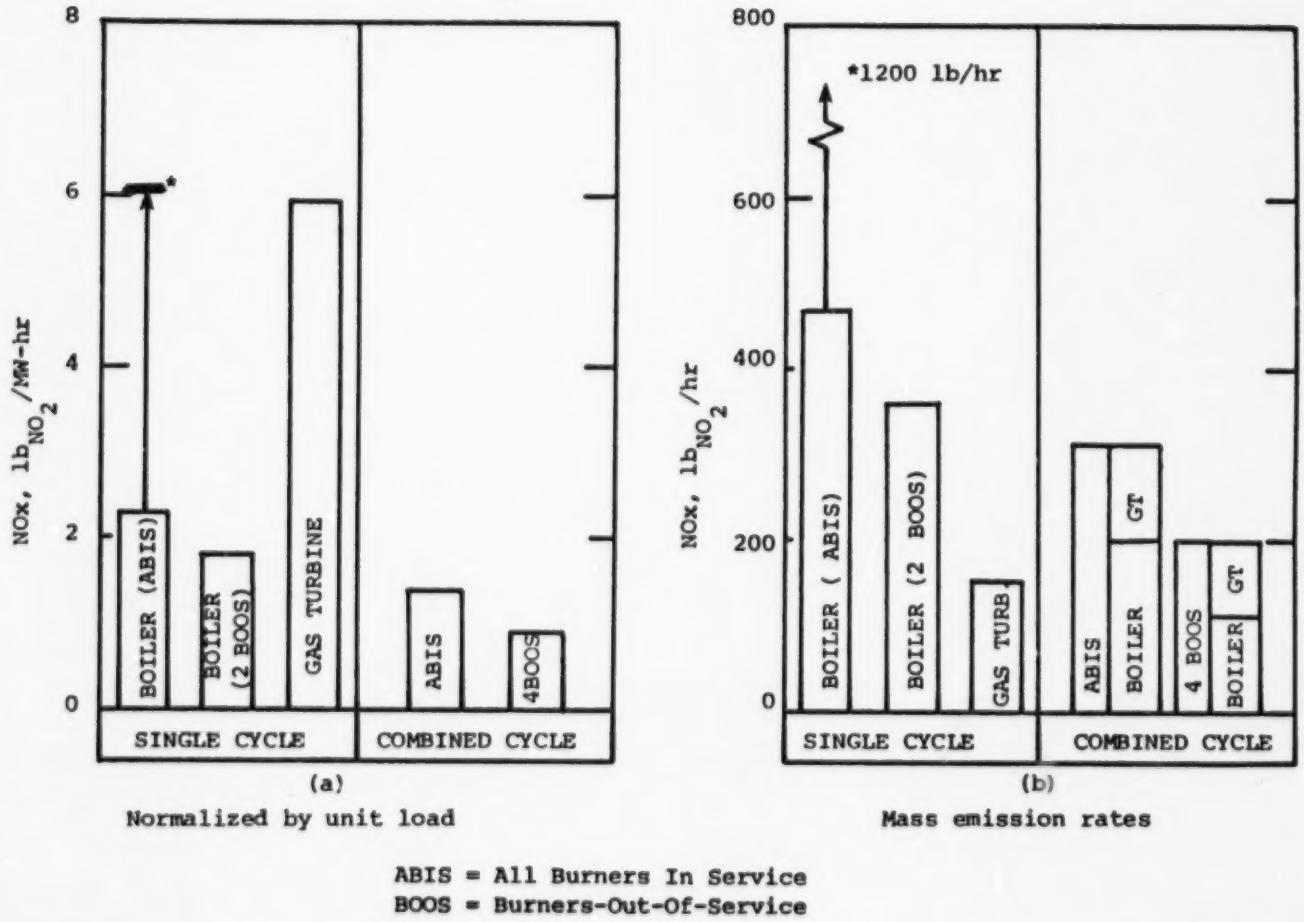


Figure 6. Effect of excess oxygen levels on NOx emissions, boiler-only operation



ABIS = All Burners In Service
BOOS = Burners-Out-Of-Service

Figure 7. Comparison of single-cycle and combined-cycle emissions. (OG&E Unit No. 7 boiler load approximately 200 MW, gas turbine load 25 MW.)

*Arrows indicate estimated increase in boiler NOx emissions if operated with normal 600°F combustion air preheat instead of ambient air.

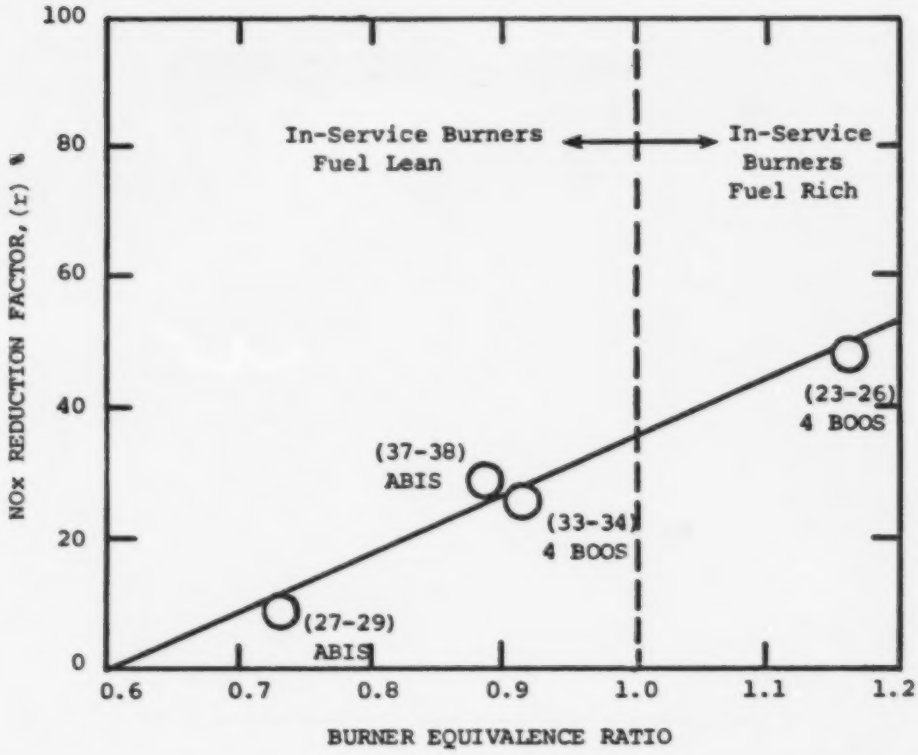


Figure 8. Correlation of NOx reduction factor (r) with the in-service burner equivalence ratio

TABLE I. BASIC TEST PLAN

Single-Cycle Operation

Variable	Range Tested	Number of Variations
Load	130 - 200 MW	3
Boiler O_2 concentration	2.25 - 5.0%	3
Burner configuration	All burners in service	1
	2 burners out of service	2
	4 burners out of service	2

Combined-Cycle Operation

Variable	Range Tested	Number of Variations
Gas turbine load	25 MW	1*
Gas turbine NO level (NH_3 injection into turbine fuel)	50 - 105 ppm	3
Boiler load	150 - 190 MW	2
Boiler O_2 concentration	1.9 - 6.2%	3
	All burners in service	1
	4 burners out of service	1
	Partial turbine exhaust bypassed to bottom hopper†	1

*Gas turbine load was essentially constant throughout the test program.
†To simulate low excess air at the burner.

TABLE II. BOILER-ONLY TEST RESULTS

Test No.	Burners Out of Service	Load MW	Flue Gas Flow lb/hr	O_2 % dry	CO ppm	NO ppm @ 3% O_2	lb/hr as NO_2	% NO Reduction
1	0	138	1.10×10^6	4.75	0	152	212	--
2	0	169	1.39×10^6	3.85	0	199	367	Baseline
3	2 (#18,19)	167	1.38×10^6	3.80	0	196	360	2%
4	4 (#17,18,19,20)	165	1.39×10^6	4.05	0	155	283	22%
5	4 (#13,14,15,16)	167	1.40×10^6	4.10	0	151	276	24%
6	0	130	1.16×10^6	5.00	0	186	268	Baseline
7	2 (#14,15)	130	1.15×10^6	4.90	0	166	240	11%
8	4 (#13,14,15,16)	130	1.16×10^6	4.95	0	138	200	26%
9	4 (#13,14,15,16)	129	1.09×10^6	4.15	0	122	174	33%
10	0	130	1.08×10^6	3.90	0	182	260	Baseline
11	0	130		5.00	0	186	263	--
13	0	169	1.37×10^6	3.60	0	200	367	--
14	4 (#13,14,15,16)	168	1.26×10^6	2.25	105	99	179	43%
15	2 (#14,15)	167	1.27×10^6	2.58	235	130	234	25%
16	0	165	1.27×10^6	2.50	0	173	311	Baseline
17	0	200	1.68×10^6	3.75	0	209	467	Baseline
18	2 (#14,15)	199	1.68×10^6	3.75	0	160	357	23%

TABLE III. SUMMARY OF COMBINED-CYCLE TEST RESULTS

Test Series	Test Description	Turb. Load MW	Boiler Load MW	Boiler O_2 % Dry	Stack CO ppm	Turbine NOx lb/hr*	Boiler NOx# lb/hr*	Stack NOx lb/hr*	r (%)	SR_b †	ϕ_b §
27,28,29	ABIS	26	150	6.2	0	146	96	229	10	1.37	0.73
37,38	ABIS	24	190	2.7	0	156	193	305	28	1.12	0.89
30,31,32	ABIS, hopper bypass)	25	150	5.8	0	147	145	293	0	--	--
23,24,25 26	4 BOOS (#13, 14,15,16)	25	198	1.9	80-125	148	115	195	49	0.86	1.16
33,34	4 BOOS (#13, 14,15,16)	23	150	6.2	0	137	129	229	27	1.10	0.91

* As NO_2

† SR_b = stoichiometric ratio of the in-service burners, based on the boiler O_2 measurement $(O/F)_{stoichiometric}$

$SR_b > 1 \longrightarrow$ oxygen lean

$SR_b < 1 \longrightarrow$ fuel rich

§ $\phi_b = 1/SR_b$

\# Determined by a least squares fit; thus may not exactly satisfy the equation

$\dot{m}_{NO_s} = \dot{m}_{NO_b} + (1-r)\ \dot{m}_{NO_{gt}}$, using the values in the table.

TABLE IV. COMPARISON OF COMBINED- AND SINGLE-CYCLE EMISSIONS

Single Cycle Operation

Boiler (cold air operation, ABIS): (467 lb/hr)/(200 MW) = 2.3 $\frac{\text{lb } NO_2}{\text{MW-hr}}$

(cold air operation, 2 BOOS): (357 lb/hr)/(199 MW)

= 1.8 $\frac{\text{lb } NO_2}{\text{MW-hr}}$

Gas turbine: (148 lb/hr)/(25 MW) = 5.9 $\frac{\text{lb } NO_2}{\text{MW-hr}}$

Combined-Cycle Operation

Combined cycle (ABIS) : (305 lb/hr)/(24 MW+190 MW) = 1.4 $\frac{\text{lb } NO_2}{\text{MW-hr}}$

Boiler NOx (ABIS): (193 lb/hr)/(190 MW) = 1.0 $\frac{\text{lb } NO_2}{\text{MW-hr}}$

Combined cycle (4 BOOS): (195 lb/hr)/(198 MW+25 MW) = 0.9 $\frac{\text{lb } NO_2}{\text{MW-hr}}$

RELATIONSHIP BETWEEN NO_x AND FINE PARTICLE EMISSIONS

By:

M. W. McElroy and R. C. Carr
Air Quality Control Program
Coal Combustion Systems Division
Electric Power Research Institute
Palo Alto, California 94303

ABSTRACT

Data from EPRI-sponsored field test programs at pulverized coal-fired utility power plants indicate that boiler combustion conditions producing low NO_x emissions also tend to suppress the generation of fine, submicron particulate matter. Specifically, the mass of fine particles measured at the outlet of boilers in the 0.1-micrometer diameter region are reduced by up to one or more orders of magnitude when low NO_x emissions are observed. These observations are consistent with the present theories of volatilization/condensation processes believed to be responsible for particle generation in the fine particle size region.

The significance of this discovery is that particulate collectors (electrostatic precipitators and fabric filter baghouses) generally exhibit a minima in collection efficiency at this particle size region. Furthermore, these particles: (1) can contribute to visibility problems due to particle growth within the plume, and (2) have been implicated as bad actors from a health effects standpoint due to their possible enrichment in trace elements and unfavorable transport properties. It now appears that these deficiencies inherent to particulate control devices may, in part, be overcome by the application of NO_x combustion control.

ACKNOWLEDGEMENTS

The data presented in this paper are derived from EPRI test programs conducted by Meteorology Research, Inc. (MRI) under the direction of Dr. David Ensor. Special credit is given to Mr. Gregory Markowsky of MRI for the development of crucial fine particle data reduction methods.

RELATIONSHIP BETWEEN NO_x AND FINE PARTICLE EMISSIONS

INTRODUCTION

Over the past several years EPRI has supported a number of field test programs at pulverized coal-fired utility boilers to evaluate state-of-the-art particulate control devices, namely electrostatic precipitators and fabric filter baghouses. A major objective of this continuing effort is to provide the utility industry with basic information on particulate collection performance with emphasis on particle size dependent collection efficiency, trace element emissions and stack opacity. Operational and economic data are also obtained to provide the necessary information for a complete assessment of control technology options.

The field test approach used in these evaluations involves monitoring of the boiler and combustion processes (i.e., the source of particulate matter) during the particulate control device testing. As a consequence of this total systems approach to field testing, and the emphasis on fine particle collection efficiency measurements, a conspicuous dependence emerged between NO_x emissions and the generation of fine submicrometer size particles in the boiler. Specifically, it appears that suppressed fine particle generation is associated with lower NO_x emissions. This observed dependence between NO_x and fine particles is the subject of this paper. Before presenting these results and their ramifications, fundamental characteristics of particulate matter emissions from coal fired boilers are first briefly discussed.

CHARACTERISTICS OF PARTICULATE MATTER EMISSIONS

The distribution of particulate matter (fly ash) mass over the particle size range at the outlet of a 520 MW opposed wall fired boiler[1] is shown in Figure 1. These data are especially significant since they represent the first time that a bimodal particle size distribution was measured in the field. The bimodal distribution consists of (1) a fine particle mode (aerosol

spike) at approximately 0.1 micrometer diameter and (2) a large particle mode which actually reaches a peak and then tails off to the larger particle sizes. It should be emphasized that these data (and data contained in subsequent figures) are based on measurements taken before the particulate control device and therefore represent boiler outlet conditions. The fine particle mode was measured with an extractive Thermo-Systems electrical aerosol size (mobility) analyzer. The large particle mode was measured in situ with a conventional cascade impactor. Prior to discovery of the aerosol spike, it was very common practice to artificially extend size distribution curves to zero at the low end of the cascade impactor data.

The format of Figure 1 is well known to those involved in the particle measurement sciences but may be a little confusing to those not familiar with reduced particle size distribution data. For purposes of interpretation this differential mass plot can be viewed as a mass histogram where the area under the curve is equal to total mass. Thus, the contribution of particulate mass within a specific size range to the total mass can be easily visualized by comparing the area under the curve in the region of interest to the total area. Clearly, the aerosol spike represents a very small fraction of the total mass of particulate matter leaving the boiler. In this case, the mass of the spike is roughly one percent of the total mass, or 99 percent of the total number of particles. This may seem insignificant until one realizes that conventional particulate control devices (electrostatic precipitators and baghouses) typically exhibit reduced collection efficiency in this particle size range. At this particular boiler, which was equipped with a large electrostatic precipitator, the particles in this size range represented about 20% of the stack emissions on a mass basis.

It was apparent from these early tests that the fine particulate matter can represent a significant fraction of total stack emissions. The importance of this from an environmental standpoint stems from the fact that these small particles (1) can grow once in the atmosphere due to agglomeration and contribute to plume opacity and ambient visibility impairment; (2) serve as condensation sites and catalyze atmospheric chemical reactions and (3) are highly respirable. Furthermore, there has been much concern that these particles might be enriched in trace elements.

In retrospect, the discovery of the aerosol spike should not have been totally unexpected. Flagan at Cal Tech[2] independently predicted the presence of the aerosol spike at about the same time that the above measurements were made, based on a theoretical model of particle formation during coal combustion. Figure 2 is a comparison of the previous data to theoretical predictions based on Flagan's model of particle formation involving (1) high temperature volatilization of ash components followed by (2) condensation and coagulation of the volatile material as the gases cool toward the boiler exit. Note that for comparison purposes between theory and field measurements, the results are presented on a particle number basis in contrast to a mass basis used in the previous figure.

Since the data in Figure 1 were obtained, a number of boilers have been tested and they all to some degree exhibit an aerosol spike and a bimodal particle size distribution. This leads to a conclusion that the aerosol spike is a generic feature of fly ash generated in combustion processes occurring in conventional pulverized coal boilers.

Figure 3 summarizes particle size distribution data from six utility boilers of varying designs burning different coals. An obvious feature of these data is that the large particle mode seems to be highly variable from unit to unit. Careful examination of these data suggest that the large particle mode may in fact be a superposition of one or more discrete particle modes. The shape and variability of the large particle mode is more than just a simple effect of variations in total coal ash content and is an area of research beyond the scope of this paper. For simplicity, the large particle mode as discussed here is considered as a single particle mode.

The fine particle distribution is also highly variable which is more obvious in a blow up of the fine particle region as shown in Figure 4. The important aspects to note are (1) the aerosol spike is very monodisperse (narrow) which is consistent with the homogeneous gas phase condensation formation theory and (2) the spike appears to occur at essentially the same particle diameter in all units.

Table 1 is a summary of the submicron mass data shown in the previous figures. Note that the ash content as evidenced by total mass emissions varies nearly an order of magnitude from unit to unit. The percentage of total mass represented by the fine particle spike is also variable. However,

there is no simple correlation apparent between ash content and mass of aerosol spike.

CORRELATION BETWEEN NO_x AND FINE PARTICLES

It was implied earlier that there was an observed connection between NO_x emissions and the quantity of fine aerosol generated in the boiler. Figure 5 is a summary of the aerosol spike mass data generated to date, plotted vs. NO_x. There is considerable scatter in the correlation which can be attributed at least in part to a very poor quantitative understanding of fine particle generation mechanisms. However, it is quite apparent that as NO_x increases the relative mass of the aerosol spike also increases. Although a correlation between NO_x and fine particulate matter was not originally sought or expected, as more and more field data were collected it became apparent that a correlation may exist. Theories of particle formation are still evolving and an explanation can only be speculative. From a very simplistic standpoint one might hypothesize that the temperature time history during combustion processes may be a critical factor common to both formation of submicrometer aerosol and NO_x. One might argue that the hotter temperature which may enhance NO_x formation (especially in the predominately pre-NSPS boilers represented here) may also volatilize more coal ash constituents leading to the relationship observed. Nevertheless, based on information to date it appears that attempts to reduce NO_x via combustion control may have a beneficial side effect, i.e., reduce fine particle generation and emissions. The possibility of continued beneficial effects at NO_x emission levels below the range of NO_x data presented here remains to be verified.

To illustrate the very rudimentary state of understanding of fine particle generation and its connection with NO_x, Figure 6 indicates the day to day variability of the aerosol spike emissions observed at one plant. In this particular case the quantity of submicron aerosol varied significantly under repeated boiler conditions. NO_x and boiler load remained constant during the tests.

SUMMARY

Figure 7 reemphasizes the significance of the aerosol spike as it relates to particulate emission control. Here the particle collection performance of a very high efficiency baghouse and a large electrostatic precipitator are compared.[3] Note that in the region of the aerosol spike there is a minimum in collection efficiency for both control devices. Obviously then the presence of fine particles can have a pronounced impact on control device performance and selection. It appears that this deficiency inherent to particulate control may in part be overcome by application of NO_x combustion control.

REFERENCES

1. Ensor, D.S., et. al. Evaluation of the George Neal No. 3 Electrostatic Precipitator. EPRI Report FP-1145, August 1979.

2. Flagan, R.C. and S.K. Friedlander. Particle Formation in Pulverized Coal Combustion -- A review. In: Proceedings of the Symposium on Aerosol Science and Technology at the 82nd National Meeting of the American Institute of Chemical Engineers, Atlantic City, New Jersey, August 29 - September 1, 1976.

3. Carr, R.C. Performance of Electrostatic Precipitators and Baghouses. Proceedings of EPRI Topical Conference: Focus on Particulates, EPRI Report P-80-2-LD, June 1980.

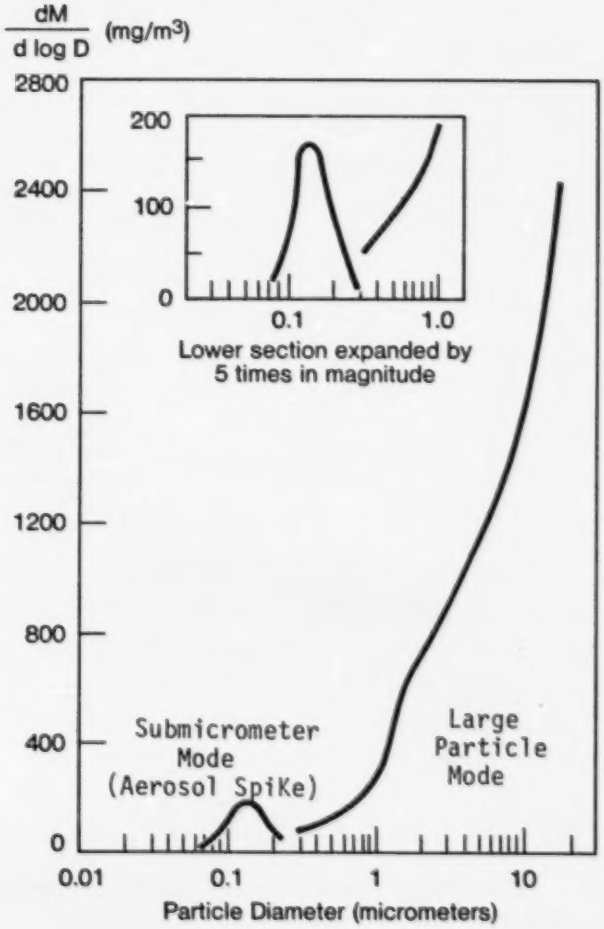


Figure 1. Differential mass particle size distribution at boiler outlet illustrating bimodal nature of particulate matter (520 Mw coal fired boiler)

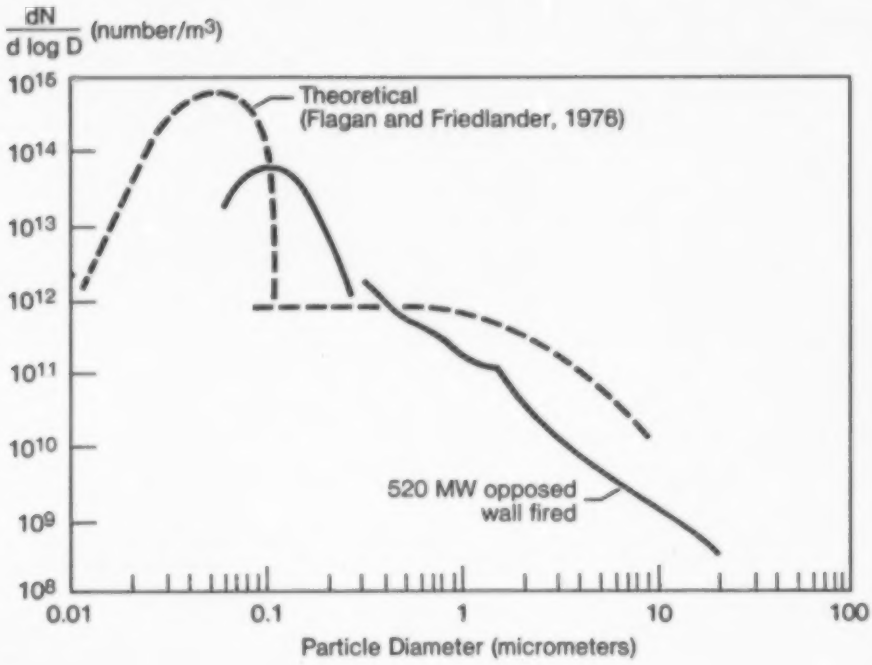


Figure 2. Comparison of measured differential number size distribution with theoretical prediction

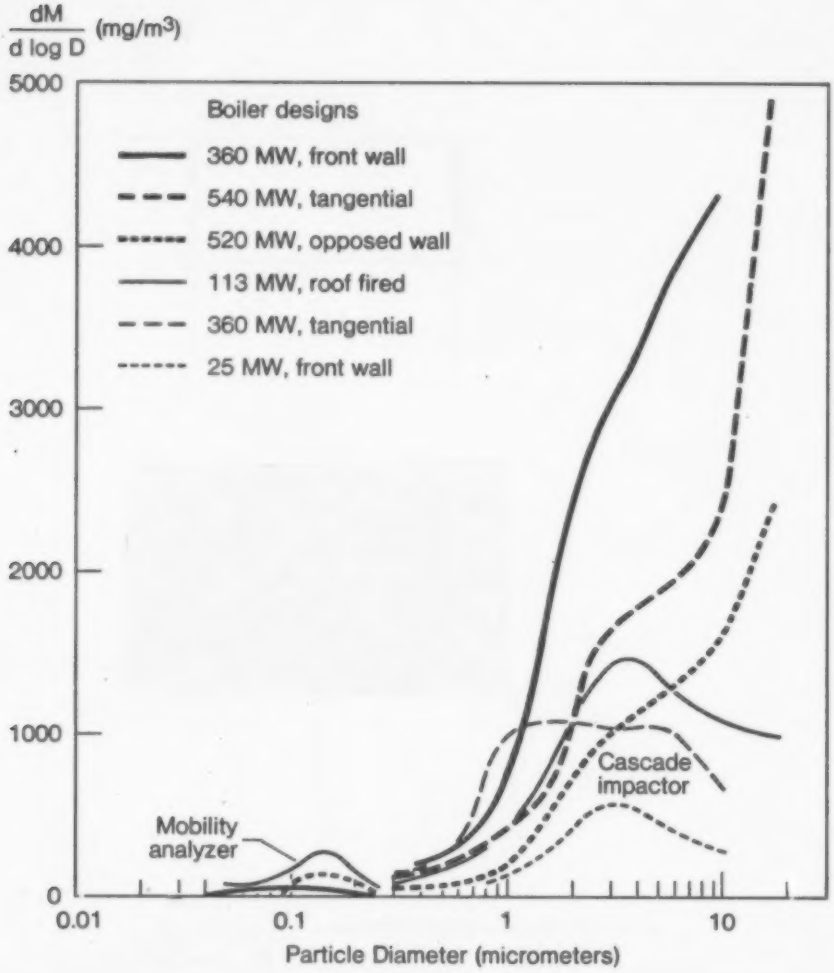


Figure 3. Differential mass particle size distribution for six coal fired uitlity boilers

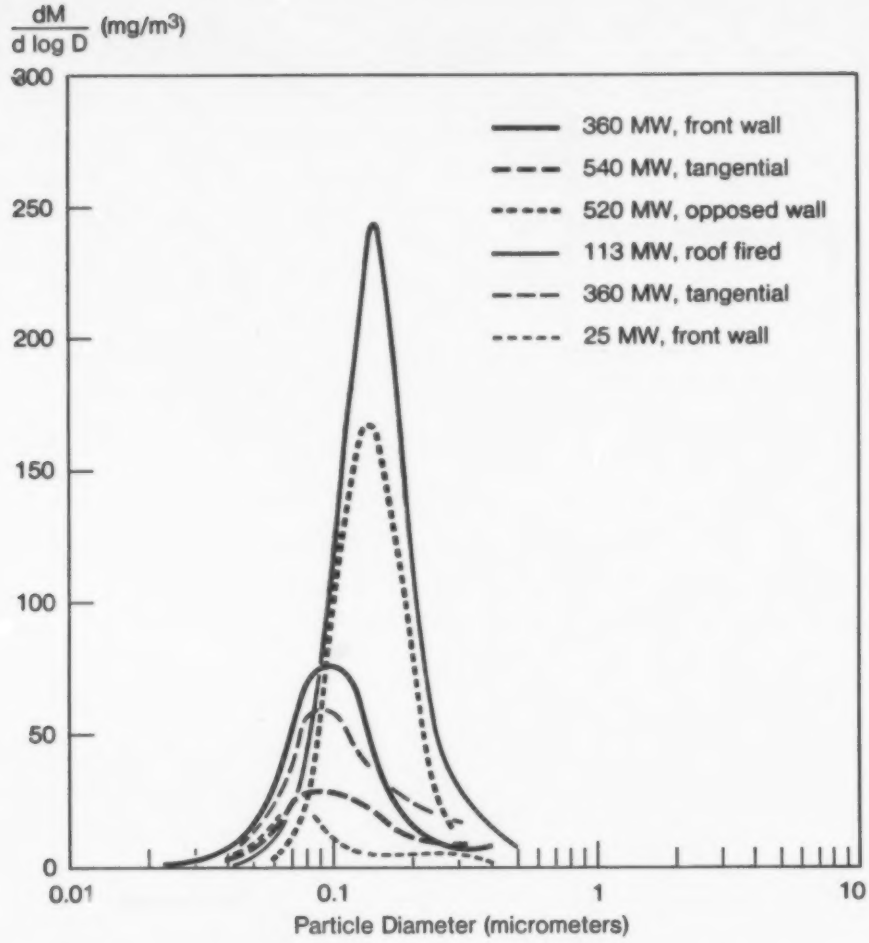


Figure 4. Aerosol Spike Differential Mass Particle Size Distributions for Six Utility Boilers

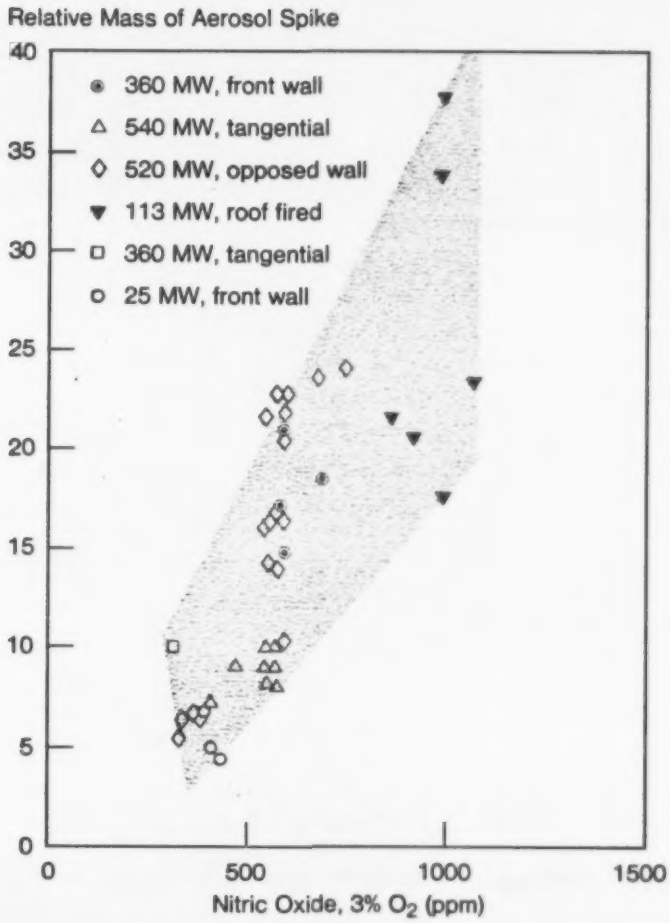


Figure 5. Relationship Between NOx Emissions & Aerosol Spike

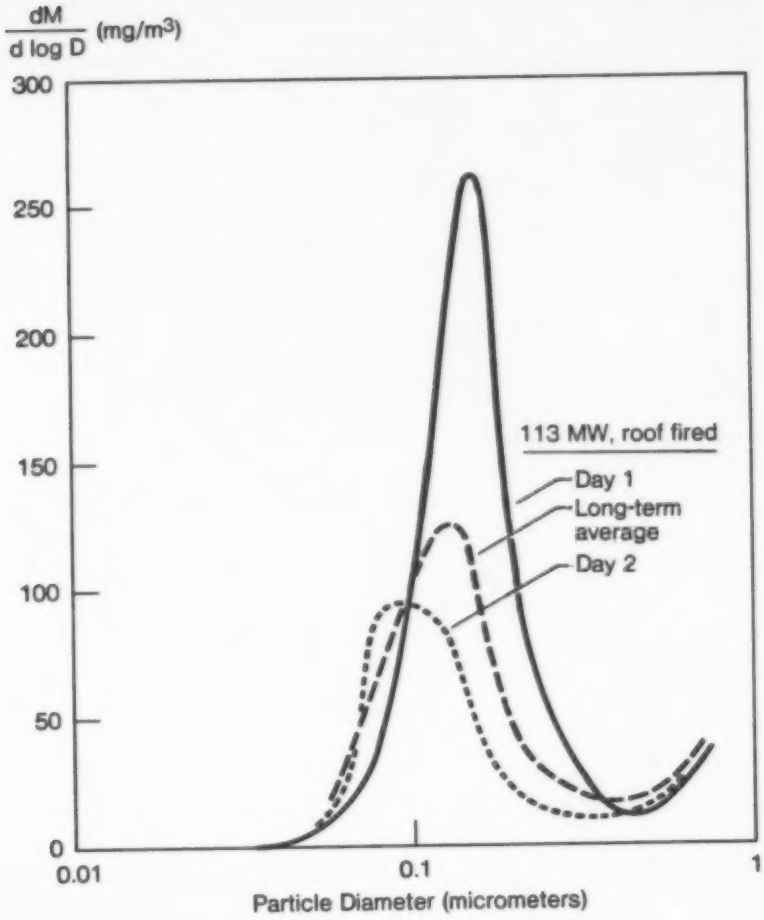


Figure 6. Variations in Aerosol Spike at Constant Boiler Load

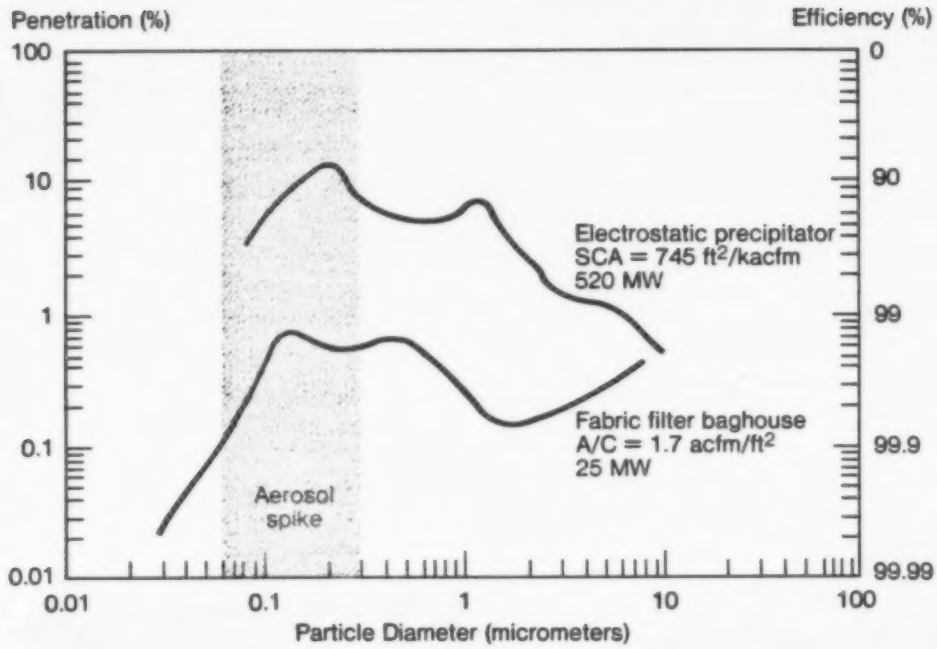


Figure 7. Size Dependent Collection Efficiency of Particulate Controls Illustrating Minimum Performance in Region of Aerosol Spike

TABLE I

TOTAL & FINE PARTICULATE EMISSION SUMMARY FOR SIX UTILITY BOILERS

Boiler Description	*Total Mass grams/m^3 (grains/ft^3)*	*Mass <2μm (percent)*	*Mass of Aerosol Spike (percent)*
360 MW, front wall fired Western, low sulfur, subbituminous	10.5 (4.6)	7	0.3
540 MW, tangential fired Eastern, high sulfur, bituminous	9.5 (4.2)	4	0.2
520 MW, opposed wall fired Western, low sulfur, subbituminous	6.4 (2.8)	4	1.3
113 MW, roof fired Western, low sulfur, subbituminous	3.4 (1.5)	8	2.2
360 MW, tangential fired Western, low sulfur, subbituminous	2.3 (1.0)	20	0.9
25 MW, front wall fired Western, low sulfur, subbituminous	1.7 (0.75)	8	0.5

COMMERCIAL EVALUATION OF A LOW NO_x COMBUSTION SYSTEM AS APPLIED TO COAL-FIRED UTILITY BOILERS

By:

S. A. Johnson and T. M. Sommer
Babcock & Wilcox Company
Alliance, Ohio 44601

ABSTRACT

Development testing of an advanced, two-stage combustion system, capable of limiting NO_x emissions from pulverized coal-fired boilers to less than 0.2 LB_m $NO_2/10^6$ Btu has been completed. Test programs have been conducted on both a 1.2 MW_T and 10.2 MW_T system. These tests have confirmed that NO_x emissions can be correlated to a dimensionless parameter proportional to the second stage flame temperature. In addition, scaleup criteria were formulated which allowed the design of commercial scale low NO_x combustion systems.

Subsequently, a detailed engineering evaluation was performed on two candidate applications of this technology. The objectives of that study were: 1) to refine scaleup correlations and design procedures; 2) to conceptually design a steam generator incorporating the two stage combustion concept; 3) to economically evaluate that design as compared to a conventional, post-NSPS steam generator design; and 4) to identify areas of commercial concern with the new designs and to recommend further research to address these concerns.

This paper summarizes the significant results and conclusions from the test programs and the engineering study. The favored Venturi furnace system is expected to limit NO_x emissions from coal-fired boilers to less than 0.2 LB $NO_2/10^6$ Btu, while increasing the capital cost of the boilers by significantly less than the projected costs of tailend NO_x removal systems to meet future strict NO_x emission standards.

BEGIN FIRST LINE OF TEXT HERE
TYPING GUIDE SHEET
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD, BEGIN SECTIONS HERE

INTRODUCTION

In 1976, The Babcock & Wilcox Company (B&W) entered into a contract with the Electric Power Research Institute (EPRI) to investigate practical methods for minimizing the emission of nitrogen oxides (NO_x) from coal-fired utility boilers. The goal of this research was to achieve 100 ppm of NO_x using only combustion modifications. It was achieved, as reported in the previous EPRI NO_x Control Seminar [1], by utilizing an advanced staged combustion technique called the primary combustion furnace.

The primary combustion furnace was conceptualized to limit NO_x emissions through effective control of temperature and oxidant availability. Unlike conventional staged combustion, where separation of stages may be ambiguous, the B&W process consists of two individual, physically separated combustion chambers. The first stage is operated with substantially less than the amount of air necessary to complete combustion. Under these conditions, the fuel-bound nitrogen compounds tend to react to form molecular nitrogen within the fuel-rich regions of the flame. After giving up some of their heat to combustor surroundings, the products of partial combustion then pass into the second-stage furnace where additional air is added to complete combustion. NO_x formation in the second stage can be further suppressed (or first-stage NO_x can be reduced) by limiting the second-stage, flame-zone temperature.

Initial testing of this concept took place on a 4-million Btu/hr (1.2 MW_T) device. These tests, aimed toward understanding of the parameters which affect NO_x formation and reduction, revealed that NO_x could be limited to 100 - 150 ppm by operating with a first stage stoichiometry of 60% - 80%, as long as the second-stage, flame-zone temperature (measured) was less than about 1800°F. A plot of NO_x emissions, as a function of a characteristic, measured flame temperature for these small-scale tests is reviewed in Figure 1.

BEGIN LAST LINE OF TEXT
BOTTOM OF IMAGE AREA, OUTSIDE DIMENSION FOR TABLES AND ILLUSTRATIONS

EPA-287 (Cin.)
(4-76)

Subsequently, prototype-scale testing was completed on a 35-million Btu/hr (10.2 MW_T) scale. The purpose of this portion of the test program was twofold:

- To confirm that the effects of the various operating parameters on NO_x, noted during model furnace testing, would occur in a similar manner on the prototype system.

- To develop a scale-up strategy, based on the results of model and prototype testing, to be used to predict NO_x emissions from a commercial system.

This information was then factored into a detailed engineering design study performed by B&W's Fossil Power Generation Division. This study included the following tasks:

- Refinement of scale-up correlations and design procedures.

- Design of a 650-MW_e steam generator to accommodate the advanced staged combustion concept.

- Economic evaluation of the new design as compared to a conventional 650-MW_e, coal-fired boiler built to meet the original EPA New Source Performance Standard of 0.7 lb $NO_x/10^6$ Btu.

- Identification of potential commercial concerns or unknowns included in the new design, as well as a recommendation of research to address those concerns.

This paper is an update of the work accomplished since the last EPRI NO_x Seminar in 1978. Results from the prototype test program are presented and compared to previous model-scale data. Pertinent highlights of the boiler design study and commercial evaluation will also be discussed.

PROTOTYPE-SCALE TEST FACILITY

The prototype-scale test program was conducted in a four-drum Stirling boiler rated at 40,000 lb/hr of steam. This boiler is located at B&W's Alliance (Ohio) Research Center.

To transform this boiler into the Low-NO_x Combustion System (LNCS) shown in Figure 2, a separate first-stage furnace was mounted on the burner wall. This furnace consisted of a rectangular tunnel with a five-foot-square cross section by about 13 feet long. It differed from the 1.2 MW_T device in that it was inclined at a 30° angle to minimize the accumulation of solids on the furnace floor. The transition between the first and second stage consisted of a converging section having a 55° included angle and terminating at a rectangular opening 19-1/2 inches wide by five feet high. This furnace was designed to accommodate the same residence time as the 1.2 MW_T device when firing at 10 MW_T (35 million Btu/hr).

Cooling of the first-stage furnace was achieved by circulation of pressurized water through the membrane-wall tubes. Total first-stage heat absorption could be determined from the measured temperature gain of the subcooled water, while chordal thermocouples were used to measure local

heat flux at 24 locations in the first stage.

Second-stage air was injected through pivoting, rectangular-slot nozzles located on either side of the first-stage furnace exit. These slots were sized to duplicate the second-stage air velocities from the 1.2 MW_T system.

As in the small-scale test facility, an ample number of sample probe access ports were located in both stages of combustion. These ports are diagrammed in Figure 3. As shown, NO_x, O_2, CO and CO_2 concentrations in the stack flue gas were routinely measured and continuously recorded. Particulate samples were also extracted from the stack for determination of combustion completeness. Temperature profiles in the second-stage ignition zone were taken for the majority of the test runs, while less routine measurements included HCN, NH_3, NO_x, O_2, CO, CO_2, inflame solids and temperature profiles in the first-stage furnace. It is impossible to report all these results in the space allotted. (A full report is forthcoming from EPRI [2].) However, the following sections describe the results having the most impact on the design of a commercial unit.

COMPARISON OF MODEL AND PROTOTYPE RESULTS

Effects of input variables were investigated during both the model-scale and prototype-scale tests. In this section, parametric influence of pertinent variables on NO_x emissions, as well as a comparison between test results from the two combustion systems, are presented.

Effect of First-Stage Air/Fuel Stoichiometry on NO_x

The prototype tests verified that an optimum overall air/fuel stoichiometry of 60% - 75% exists at which NO_x emissions could be minimized. The effect of stoichiometry on NO_x is shown in Figures 4 and 5, first, for the prototype system with and without flue gas recirculation to cool the second-stage flame, and second, for comparison of the model and prototype furnaces. At very low stoichiometries, first stage NO_x formation was low, but stack NO_x increased because the large amounts of cyano species (>500 ppm) produced in the first stage were converted to NO_x through oxidation reactions in the second stage. This conversion was enhanced by high, second-stage flame temperatures, since less heat was released and removed from the first stage.

At high stoichiometries, NO_x formation in the first stage was not as effectively suppressed. Even though reduction of NO_x still took place across the second-stage flame front as a result of higher first stage heat removal and lower, second-stage temperatures, NO_x emissions remained high because first-stage NO_x formation was high under local oxidizing conditions. The reduction of NO_x noted across the second-stage flame front can be seen by comparing the first stage exit NO_x line to the stack NO_x curves in Figure 4.

It can be seen from Figure 5 that NO_x emissions from the two furnaces were very similar at any given first-stage stoichiometry. The prototype furnace generally produced slightly higher NO_x at a particular stoichiometry due to decreased heat removal surface in the larger furnace.

Effect of Gas Phase Stoichiometry on NO_x

Although it was convenient to correlate NO_x emissions with overall air/fuel stoichiometry, this parameter can be misleading when applied to coal combustion because a significant fraction of the coal may remain in the solid phase. This would be especially true in combustion systems characterized by low temperatures or short residence times in the flame zone.

The first stage of the B&W low NO_x combustion system was fired with a low-turbulence burner under low-temperature conditions (2000-2500°F). Stratification of the mixture inside the first-stage combustor can be seen from Figure 6 in which contours of constant gas-phase stoichiometry are plotted for a test run at an overall stoichiometry of 70%. The gas-phase stoichiometries were calculated from the measured gas composition at each sampling plane located 3.3 feet (1 meter) and 6.7 feet (2 meters) from the burner outlet.

This figure shows that local gas-phase stoichiometries very seldom approached the overall value. In fact, much of the flame periphery remained under oxidizing conditions.

Since NO_x formation occurs primarily in the gas phase [3, 4], it would seem that to limit first stage NO_x, one should minimize the gas-phase stoichiometry. This can be seen from the contours of constant fuel nitrogen conversion plotted on Figure 7. Since low conversion closely corresponded to low, gas-phase stoichiometries (as illustrated by the contour having a gas-phase stoichiometry of unity superimposed on the plots), an attempt was made to increase the uniformity of the mixture by using an impeller to

disperse the coal into the air stream. The resultant gas-phase stoichiometry contours are shown on Figure 8. It can be seen that the local gas-phase stoichiometires were much more uniform, but that little improvement was made in achieving more reducing conditions. As a result, first-stage NO_x changed very little. The largest effect of the change, however, was a 4% decrease in combustion efficiency due to severe flame impingement on the first-stage furnace side walls.

Effect of Second Stage Temperature on NO_x

Early in the model-scale test program, it became obvious that second-stage, flame-zone temperature had an overriding effect on NO_x emissions from this combustion system. With constant conditions in the first stage, the second-stage NO_x could be increased or decreased, depending on the second-stage, flame-front temperature. Additionally, the first-stage NO_x concentration could be increased by nearly a factor of three without significantly changing stack NO_x concentrations. This startling result has been reported elsewhere [1, 5] and need not be explained in detail here.

Unfortunately, the early correlation between NO_x and second-stage flame temperature involved a single characteristic measured temperature. Since such a temperature could not be easily estimated during the design of large units, another more meaningful correlation was necessary.

As a first attempt, NO_x emissions were correlated with a calculated, theoretical, second-stage temperature, which was defined as the temperature of the second-stage mixture if combustion were completed under adiabatic second-stage conditions. This correlation is shown on Figure 9. It can be seen from this figure that a consistent relationship existed between NO_x and

theoretical second-stage temperature. But, by segregating the data, distinctive curves could now be drawn for each furnace load. It is believed that the load effect, which was not noted in the correlation with measured temperatures, was probably caused by the fact that second-stage heat losses (clearly a function of load) were not accounted for in the theoretical calculation. The successful design correlation which normalized the load effect is described below.

DEVELOPMENT OF AN NO_X CORRELATION PARAMETER (NCP)

An expression incorporating the parameters influencing second-stage temperature, while normalizing the load effects, is given below:

$$\frac{Q\ (1 - \beta)}{Q_N\ (1 + f)}$$

In this parameter, Q and Q_N are the load and the nominal load of the furnace; β is the amount of first-stage heat removed, expressed as a fraction of the fuel-energy input; and f is the amount of recirculated flue gas expressed as a fraction of the total coal and combustion air-flow rates. Nominal load was chosen as that load which would maintain mean-gas-residence time similarity between model and prototype furnaces.

A closer look would reveal that this parameter is actually the combination of the following two terms:

$$\frac{Q\ (1 - \beta)}{Q\ (1 + f)} \times \frac{Q}{Q_N}$$

The first term is representative of the theoretical second-stage temperature,

while the second term is a modifier showing the effect of load changes.

A linear correlation of NO_x emissions with NCP, established from a least-squares fit of all data, is shown in Figure 10. Data plotted include both model and prototype-scale Pittsburgh No. 8 bituminous coal test results. These data cover a first-stage stoichiometry range from 50% - 75%, and FGR from 0% - 30%. Load variation covered a range of roughly 2 to 1. It's apparent the correlation is excellent.

Figure 11 is a plot of the Montana subbituminous coal data as a function of NCP. Superimposed on this graph is the linear correlation developed from the Pittsburgh No. 8 bituminous coal data. It can be seen that the Montana subbituminous coal data are generally higher than the correlation line by roughly 25 ppm, and that the scatter of data is slightly greater. However, since the deviation is not severe, a separate correlation line for Montana subbituminous coal has not been considered necessary at this point.

It should be noted that the correlations shown in Figure 10 and Figure 11 are valid only within a restricted range. In other words, the correlation was developed for the optimized conditions only. All of the data plotted are results from tests with optimum-slot, air-nozzle direction (15°) and excess air level (about 3% excess O_2). Also, since the correlation is empirical in nature, extrapolation outside a certain range of applicability would not be appropriate. The recommended ranges of applicability for a set of input variables are listed in Table 1.

It is also evident as shown by the data plotted in Figure 10 and Figure 11 that low NO_x emissions can be consistently obtained with the LNCS. As long as the operation was optimized with respect to slot angle, excess air and reasonable load, NO_x emissions were well controlled at 100 - 200 ppm.

ESTIMATION OF FIRST-STAGE HEAT REMOVAL

Determination of the NCP is straightforward. All terms in its make-up, except the first-stage heat removal term, are basic input information. However, to complete the determination of the NCP, a method had to be devised to predict heat loss in the waterwall, coal-fired, fuel-rich, first-stage furnace. To achieve this end, a simple algebraic predictive equation was developed by combining the energy-balance equation and the radiation-balance equation for the first-stage furnace. This equation can be expressed as:

$$\frac{b\phi + c - \beta}{(1 + a\phi)\ \beta^{1/4}} = d\ \frac{HA/SC}{\bar{\varepsilon}}$$

In this equation, β is the amount of heat loss to the water-cooled furnace wall expressed as a fraction of the fuel-energy input; ϕ is the first-stage stoichiometry; a, b, c and d are coefficients determined by coal composition, heating value and combustion air preheat; HA/SC is the furnace heat release rate (the ratio between furnace-energy input and furnace surface area); $\bar{\varepsilon}$ is the system mean, gray-body emissivity. Derivation and discussion of this model equation has been detailed elsewhere[6].

The accuracy of this predictive equation was evaluated by comparing the predicted values with the experimental data. During the model and prototype-scale testing of the LNCS, measurements of first-stage heat removal were taken for two coals (Pittsburgh No. 8 bituminous and Montana subbituminous) fired in two different size furnaces at air/fuel stoichiometry ranging from 50% - 90%, and load changes from 50% to 120% of nominal load. The performance of the predictive equation was found satisfactory for all cases. Examples of the measured and predicted heat transfer for the bituminous coal are shown in Figure 12.

As the size of the first-stage combustor increases toward commercial scale, the furnace heat liberation rate increases. Therefore, at a constant first-stage residence time, first-stage heat removal would be expected to decrease as larger units are designed. This would increase the NCP and the predicted NO_x emission. Fortunately, the predicted increase in NO_x emission as a function of furnace capacity is not expected to be sizeable, as shown on Figure 13.

It can be seen that, under optimized conditions, scaling from 35 million Btu/hr to 1 billion Btu/hr should only increase NO_x emissions from 140 ppm to 160 ppm. Alternatively, NO_x emissions can be trimmed by providing more heat removal surface area in the first stage. For the prediction of first-stage heat absorption in very large furances, conventional predictive procedures were shown to be valid.

SCALE-UP PROCEDURE

The procedure for scale-up design of a low NO_x combustion system can be outlined as follows:

1. Calculate nominal load using furnace dimensions (or vice versa).

2. Calculate first-stage heat removal using appropriate methods.

3. Calculate the NCP using the input information on load, coal type, amount of FGR, etc.

4. Estimate stack NO_x concentration by using the correlation with the NCP shown in Figure 8.

5. If the calculated NCP is less than 0.4 (lower limit of confidence) take the NO_x value at 0.4. Do not extrapolate.

6. If the calculated NCP is greater than 0.8 (upper limit of confidence), the designer has failed to take full advantage of the LNCS. Redesign is recommended.

DESIGN CRITERIA FOR COMMERCIAL APPLICATION

The laboratory data collected on both low-NO_x combustion systems identified several design criteria essential for minimizing the emission of nitrogen oxides. The most significant is the second-stage flame temperature. A target adiabatic temperature of 2600°F (1700°K) was selected for the commercial design to limit NO_x emissions to 0.2 lb/10^6 Btu. The heat transfer correlation described earlier could then be used to determine the size of the primary furnace necessary to achieve that second-stage adiabatic temperature.

In order to ensure that the degree of second-stage mixing is similar to that of the laboratory devices, the commercial system will be geometrically similar in second-stage injection design. Primary furnace exit velocity, staged air injection velocity, and the direction of both flows will be duplicated in the commercial design. The design of the injection ports will be such that velocity and direction can be controlled independently to accommodate changes in load and second-stage combustion conditions.

The primary furnace will be fired with burners that are geometric duplicates of the laboratory versions. The heat input per burner will be on the order of 150 - 300 x 10^6 Btu/hr (44 - 88 MW_T). The small-scale operation of the LNCS indicated that moderate changes in burner design had little effect on NO_x emissions. Therefore, the primary objective for the commercial design will be for efficient, stable operation over a range of loads and furnace conditions. The B&W dual-register burner has proven to be an effective tool for limiting initial NO_x formation in the primary furnace. Slightly more than 20% of the total heat input to the commercial system will be absorbed

by the primary furnace walls. Both the residence time and heat absorption were calculated at the optimum first-stage stoichiometric ratio of 0.7 to minimize NO_x emissions.

COMMERCIAL DESIGN

The boiler design task of the LNCS commercial application study resulted in two different boiler designs. One design, the primary combustion furnace (PCF), utilizes the multiple, primary furnace concept, while the Venturi design has only a single primary furnace. A brief description of each design, as compared with a conventional boiler design, will highlight the differences.

Conventional Design

The boiler chosen as a basis for comparing the LNCS designs to conventional designs is shown in Figure 14. It is a 650-MW_e, balanced-draft, Babcock & Wilcox, Carolina-type radiant boiler of post-1971 design. It is arranged with a water-cooled, dry-bottom furnace, along with conventional superheater, reheater, economizer and air-heater components. The boiler was designed to produce less than 0.7 lb/10^6 Btu of NO_x (500 ppm) when firing a midwestern bituminous fuel with 49 dual-register burners in a compartmented windbox.

PCF Design

The first LNCS boiler design evaluated during this study is shown in Figure 15. It is a balanced-draft, Babcock & Wilcox, tower-type radiant

boiler also rated at 650 MW_e. The tower design proved to be more economical for this particular application because extra space was required around the boiler to accommodate the primary furnaces. This design eliminates any interference by removing the large downflow section of the convection pass found on the more conventional Carolina design. It is designed to be fired with 28 primary combustion furnaces (PCF) and utilize conventional dry-bottom furnace, superheater, reheater, economizer and air-heater components, while producing less than 0.2 $lb/10^6$ Btu NO_x (150 ppm).

An iterative, heat-rate analysis showed that the heat transferred from the primary combustion furnace containments should be utilized in the boiler itself rather than in the pre-boiler cycle. Circulation and manufacturing considerations prompted the decision to make the PCF containments an integral part of the furnace wall circuitry. However, to maintain adequate flow through that circuit, five circulation pumps were added. In addition, a flue-gas recirculation system was added for NO_x and steam temperature control.

Venturi Design

The design complexities associated with the PCF design prompted the development of an alternative LNCS boiler design. The arrangement shown in Figure 16 eliminates the primary combustion furnace containments by operating the entire lower portion of the boiler furnace at an air/fuel stoichiometric ratio less than 1. The remainder of the combustion air is injected at the constriction of the furnace formed by two wall arches. This arrangement has been designated the "Venturi" furnace design.

The primary furnace (below the arches) is fired with 28, high-input, dual-register burners. There are no circulation pumps necessary and the remainder of the boiler is almost identical to the base unit. By maintaining proper first-stage heat removal, this design is also expected to meet the 0.2 lb $NO_x/10^6$ Btu emission goal.

ECONOMIC ANALYSIS

Assuming the data collected from the laboratory testing can be extrapolated to the necessary scale, both LNCS steam generator designs should be functionally satisfactory. However, an economic analysis indicated that the Venturi design is much more cost effective. Table 2 is a summary of the cost study.

The LNCS designs both have reduced gas temperatures exiting the furnace. This requires additional convective heat transfer surface to be installed to maintain design (1005°F) steam temperatures. This surface accounts for the largest portion of the pressure-part cost increase. Additional structural steel is also necessary to support the additional furnace and convective surface and the weight added by the two furnace-wall arches in the Venturi design. The PCF design, in addition to the items mentioned above, has cost increases associated with the attachment of primary combustion furnace containments and the need to use circulation pumps.

COMMERCIAL CONCERNS

In spite of the careful consideration given each of the system designs, B&W is concerned that several phenomena, unique to staged combustion, could

cause operating difficulties in the future. The primary concerns at this time are first-stage furnace waterwall corrosion and carbon utilization. After completing the engineering study of the commercial LNCS systems, many early concerns such as prohibitive cost, complicated control systems and operating procedures, manufacturing and construction problems, development of flame safety equipment and others proved to be unjustified.

The first concern arises from operating experience which has shown increased tube metal corrosion in areas suspected of exposure to reducing atmospheres. The nature of operation of the LNCS System will expose large areas of furnace-wall tubes to reducing atmospheres.

The second concern, carbon utilization, is an area of concern due to inexperience with staged combustion in utility boilers firing pulverized coal. The second stage mixing of combustion air with combustion products and unburned fuel from the primary furnace, and its effect on carbon burnout, have not been quantified. The relatively low temperatures in the second-stage combustion zone could also reduce combustion efficiency.

CONCLUSIONS

As a result of a detailed engineering analysis of advanced staged combustion techniques as applied to a new, pulverized coal-fired boiler, it has been concluded that the EPRI/B&W Low NO_x Combustion System could be a viable commercial alternative to tail-end NO_x removal to meet future strict EPA NO_x emission standards (circa 0.2 lb $NO_2/10^6$ Btu). Due to its relative simplicity and lower capital cost, the Venturi furnace described previously most favorably embraces the concept. The PCF design, however, is

still considered a retrofit possibility, especially for cyclone units oil-fired boilers that a utility wishes to convert to coal.

Before offering this system as a commercial product, B&W will complete several additional research programs to address the remaining concerns mentioned above. The results of these programs will help refine the LNCS design and enable a more precise, second-generation estimate of material and operating costs to be made.

FUTURE WORK

The commercial concerns noted previously could best be alleviated by converting an existing utility boiler into a low-NO_x Venturi furnace based on the design and scale-up criteria developed during the system analysis study. If this were done, it would only take a few years to measure corrosion rates under actual operating conditions to determine whether a potential problem really exists. It would take a few weeks (using variable-angle, second-stage injection ports) to determine whether trade-offs exist between low NO_x emissions and acceptable carbon conversion. Most importantly, such a test would provide day-to-day operating experience to finalize control schemes and to assess reliability of system components.

Unfortunately, it is unlikely that such a test could occur in the near future. Based on preliminary discussions with a number of utilities, the following factors substantiate this opinion:

- Retrofit of a Venturi furnace would be extremely expensive due to pressure-part changes required in the lower furnace walls. Substantial funding from an outside agency (EPRI, EPA, DOE) would be required for a project of this magnitude.

- A long outage in excess of 8 weeks would probably be required to modify the unit. Most utility companies do not have enough reserve capacity to afford such an extended outage.

- Because fewer new boilers are being built, most utilities are stressing maximum availability of their existing units, even old and inefficient units. Any test program which could disrupt the production of electricity is not likely to be approved.

- At this time, many utilities are concerned that very strict NO_x emission standards will prevent widespread committment to coal because they perceive problems involving costs and plant reliability. Until strict emission standards are promulgated (requiring extensive combustion modifications or expensive tail-end NO_x removal, they will probably remain unwilling to test major modifications to reduce NO_x.

In the meantime, B&W has undertaken the following programs to provide data which will enable the risk associated with each concern to be quantified.

Furnace Tube Wall Corrosion (Background)

Fireside corrosion of waterwall tubes in coal-fired utility boilers began to be a problem in the late 1930s. The trend at that time of high furnace heat release rates, coupled with increasing steam pressure requirements, resulted in higher furnace-wall temperatures and led to increased deposits of slag on furnace waterwalls. Presence of aggressive iron and alkali sulfates in the slag layer coincided with severe loss of metal. It was further noted at this time, that low, excess-air operation greatly aggravated this corrosion problem, presumably by fluxing the slag layer and providing even more aggressive reduced sulfur compounds (H_2S, S, FeS_2) in the vicinity of the waterwall. Flame impingement often accompanied corrosion in these units, and relatively high concentrations of CO (0.5 - 6.0%) were measured in the vicinity of the wall, indicating the presence of reducing conditions.

Staged combustion of coal also results in local, gas-phase reducing conditions, as well as longer flames. During the testing of the primary combustion furnace under this EPRI contract, for instance, CO concentrations in a similar range (0.1 - 9.0%) were measured in both the model and prototype first-stage furnaces.

Mechanisms for corrosion in a reducing atmosphere are still not totally understood. Hydrogen sulfide (H_2S) gas, which is present in quantities up to 0.5% in the low NO_x system can be potentially harmful. Sulfidation attack by H_2S on metals in hydrogen-rich atmospheres has been observed in steam reformers associated with many refinery operations. The questionable effect of large quantities of hydrogen, however, makes it difficult to transfer the refinery experience to utility boiler operation.

Another possible mechanism for corrosion involves deposition of pyrite (FeS_2) on the metal surface, followed by reaction of the pyrite with the protective metal oxide layer. Removal of the oxide layer by alternating exposure to both oxidizing and reducing gases could lead to rapid metal loss. Deposition of other ash constituents (like alkali sulfides and sulfates) can also cause corrosion by diffusion of tube-metal iron into a slag layer under the deposit or by dissolving the iron oxide layer into complex iron alkali tri-sulfates.

Tube-thickness measurements made during the prototype PCF test program indicated that corrosion could be occurring on the floor of the first-stage furnace. After about 300 hours of operation, the only points where measurable metal loss took place were located on the furnace floor tubes where dry and partially fused ash accumulated. It was also observed that flame impingement occurred on the furnace floor, creating a local reducing atmosphere (see Figure 6). Gas samples taken in a plane located 6.7 feet downstream of the burner showed that the roof and sidewalls were exposed to local oxidizing conditions ranging in stoichiometry from 100% - 140%. The floor, however, maintained a gas phase stoichiometry of 85% - 95%.

Test Programs

It can be seen from the above discussion that, if waterwall corrosion takes place in a low-NO_x combustion system, it could occur as a result of one or several imperfectly understood mechanisms. In the commercialization of the low NO_x concept, it is of first importance to select potential materials for adequate (>10 years) metal life. In order to achieve this goal, two fundamental corrosion studies are planned:

1. A screening test of candidate tube metals exposed to a gas-phase atmosphere typical of that measured in previous low-NO_x combustion tests.

2. A parametric variation of furnace conditions aimed at determining the effects of various sulfur forms on corrosion rates of carbon steel. Variables could include temperature, sulfur concentration, alkali availability, oxidizing/reducing cycle, and gas phase stoichiometry. Potential methods to control corrosion, such as air curtains or flue gas inerting, could also be investigated.

In the metal screening tests, the following materials have been selected for testing:

1. Carbon steel (SA210)
2. Croloy 2-1/4
3. Type 304 and 304L Stainless Steels
4. Types 309 and/or 310 Stainless Steel
5. Incoloy 800
6. Inconel 671
7. Aluminized carbon steel via diffusion coating, dipped coating, and flame spraying
8. Chromized and Aluminized Croloy 2-1/4 and Carbon steel.

Two autoclave systems have been designed and installed at B&W's Alliance Research Center to carry out corrosion tests of these materials.

Three samples of each material will be exposed to the gas mixture (typical of the concentrations measured at 70% stoichiometry near the exit of the first-stage furnace) for three time periods. Corrosion rates for two of the three samples removed after each time period will be determined by loss-of-weight measurement. The third sample of each material will be examined by electron microscope to determine composition and structure of the scale for comparison with unexposed archive samples.

The objective of these tests is to compare the resistance of each material to sulfidation attack under conditions of constant temperature and gas composition. The data should also provide some qualitative information concerning the effects of time, temperature and localized sulfur activity on corrosion rates. Based on this information, initial Venturi furnace designs will consider the cost/benefit dichotomy of corrosion resistent materials in zones (such as the lower arch) where highly reducing conditions are likely near the wall.

In the event that gas-phase sulfidation by H_2S or S_2 is <u>not</u> the dominant mechanism of corrosion, B&W is planning a subsequent corrosion study beginning in calendar year 1981. Additional tests beyond the screening tests will be required at conditions more closely simulating the low-NO_x furnace conditions, including the effects of ash deposits. In this study, further information will be developed concerning corrosion rates for only those materials that are deemed acceptable from the material screening study. Although detailed plans have not as yet been made, the following outline contains our current thoughts:

- Three sets of samples should be provided for each material: bare metal samples, samples coated with a uniform layer of FeS_2 (iron pyrite) and samples coated with a layer of sintered flyash from a high-sodium western coal.

- Samples should be exposed at constant temperature to a typical fuel-rich gas for 500, 1000, and 2000 hours.

- Samples should be exposed to various temperatures ranging from 500°F to 900°F.

- Samples should be exposed to periodic addition of O_2 to the gas composition.

In addition to the measurement of corrosion rates, analysis may include detection of SO_3 in the reactor exit gases, and sulfur forms existing in the corrosion products. In particular, evidence of pyrosulfate or alkali tri-sulfate will be sought. Sulfide penetration into the metal substrate will also be measured since its presence could indicate future catastrophic failure of materials that initially show low corrosion rates.

CARBON UTILIZATION (Background)

The concern that carbon burnout may be unacceptable in a full-scale Venturi furnace operating in the low NO_x mode stems from the following considerations:

- During prototype testing of the Pittsburgh seam #8 bituminous coal, large agglomerates of sticky particles which formed in the first-stage furnace were not completely combusted in the second state. The sub-bituminous coal, however, which did not agglomerate, achieved 99+% burnout under all conditions. Carbon burnout for each of these fuels is illustrated in Figure 17.

- Carbon burnout depends on the amount of time that the particle is exposed to high temperatures in the presence of oxygen. The local oxygen concentrations, in turn, depend on the penetration and entrainment of the second-stage air jets into the first-stage exit gases. In the prototype tests, the air had to penetrate across a jet approximately 20 inches wide, but in the commercial Venturi furnace, the fuel-rich jet is 21 feet wide.

Work done on the model and prototype low-NO_x systems at B&W showed that there was a slight trade-off between increased second-stage mixing (i.e., higher air jet velocity or higher jet penetration angle) to achieve better burnout, and decreased mixing to minimize second-stage NO_x. It is possible that the same conditions considered optimum during the test programs would need to be refined in the field. Therefore, B&W is studying the mixing process in a full-scale Venturi furnace by utilizing advanced flow modeling techniques in order to show that complete combustion is possible under low NO_x conditions. Armed with the information from this study, B&W will then optimize the second-stage mixing during the eventual field testing of the Venturi furnace concept.

PRELIMINARY FIELD TESTING

The third major concern with commercializing the Venturi furnace concept is that the use of flue-gas recirculation fans, along with operation in an unfamiliar staging mode, may decrease the availability of early commercial units. As stated previously, extensive field testing of a demonstration unit is the only way to assess the impact of this concern. Before the demonstration unit will be accepted by a customer, however, it may be advantageous to point to preliminary field tests where boilers were subjected to "deep staging", i.e., burner air/fuel stoichiometries on the order of 0.6 - 0.8. Such tests could be conducted on an existing boiler equipped with overfire air ports. B&W has begun discussions with an electric utility that has expressed interest in participating in such a test program.

SUMMARY

In the above sections, B&W has defined interim research aimed at further defining the practical limit of NO_x control using advanced staged combustion techniques. These programs result from a detailed engineering study of the Venturi furnace, based on model and prototype test results. This low-NO_x system, as designed, seems to be a viable alternative to either tail-end NO_x reduction or the EPA burner concept, both of which will be commercially demonstrated in the near future. With the potential decrease in NO_x emission standards just around the corner, it would seem prudent for the utility industry to carry this research to its final demonstration before the alternative technologies are forced upon them.

ACKNOWLEDGEMENTS

Much of the interpretation and analysis of the data presented here was performed by Dr. Bob Yang. The authors are deeply appreciative of the technical skills and philosophical guidance contributed by Bob.

REFERENCES

1. S. A. Johnson, P. L. Cioffi, T. M. Sommer, and M. W. McElroy. "The Primary Combustion Furnace - An Advanced Low NO_x Concept for Pulverized Coal Combustion." Second EPRI NO_x Control Technology Seminar, 1978.

2. Subtask 3.2 Final Report: Results of the Prototype Primary Combustion Furnace Tests, Palo Alto, Calif.: Electric Power Research Institute Contract RP-899-1.

3. J. O. L. Wendt, D. W. Pershing, J. W. Lee, and J. W. Glass. "Pulverized Coal Combustion: NO_x Formation Mechanisms Under Fuel-Rich and Staged Combustion Conditions." 17th Symposium (International) on Combustion, The Combustion Institute, August 1978.

4. D. W. Pershing and J. O. L. Wendt. "Relative Contributions of Volatile Nitrogen and Char Nitrogen to NO_x Emissions from Pulverized Coal Flames." 83rd National Meeting of AIChE, Houston, Texas, March 1977.

5. T. M. Sommer, S. A. Johnson, and G. D. Lindstrom. "Further Development of an Advanced Low NO_x Coal-Fired Utility Boiler." ASME Winter Annual Meeting, Paper No. 79-WA/Fu-4, New York, New York, December 1979.

6. R. J. Yang, S. A. Johnson, and M. W. McElroy. "Heat Transfer Modeling for Two-Stage Pulverized Coal-Fired Combustors." Joint ASME/AIChE National Heat Transfer Conference, ASME Paper No. 80-HT-114, Orlando, Florida, July 1980.

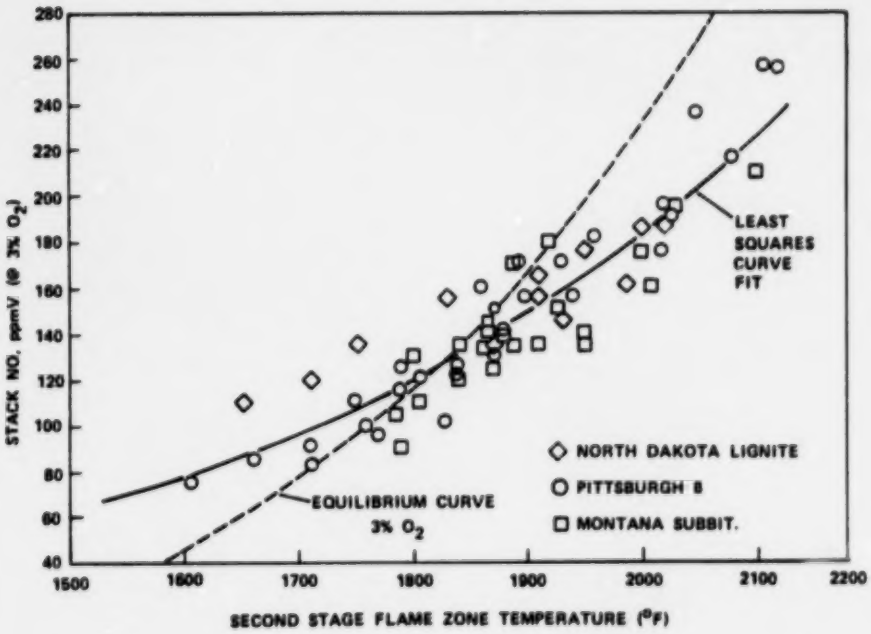


Fig. 1 NO_x emissions as a function of a measured second stage flame temperature

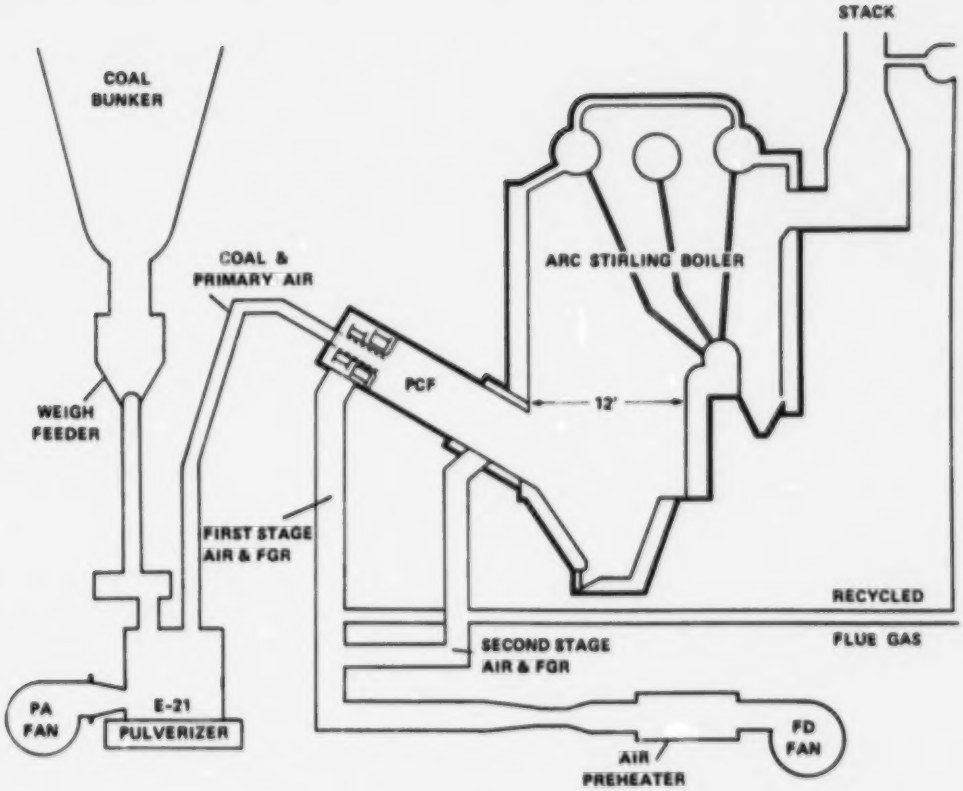


Fig. 2 Prototype scale test facility

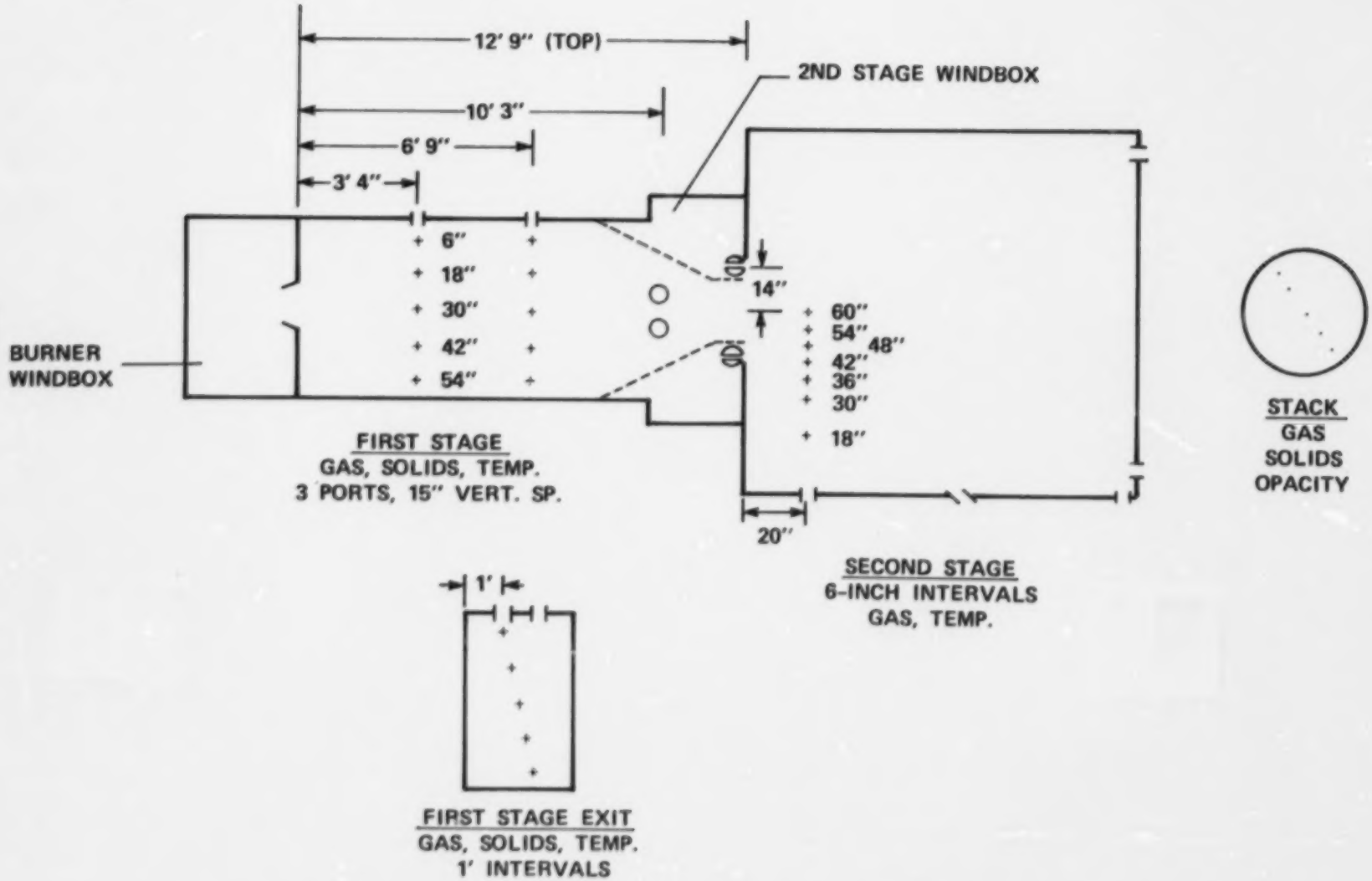


FIGURE 3 SAMPLE PORT LOCATIONS (PROTOTYPE TEST FACILITY)

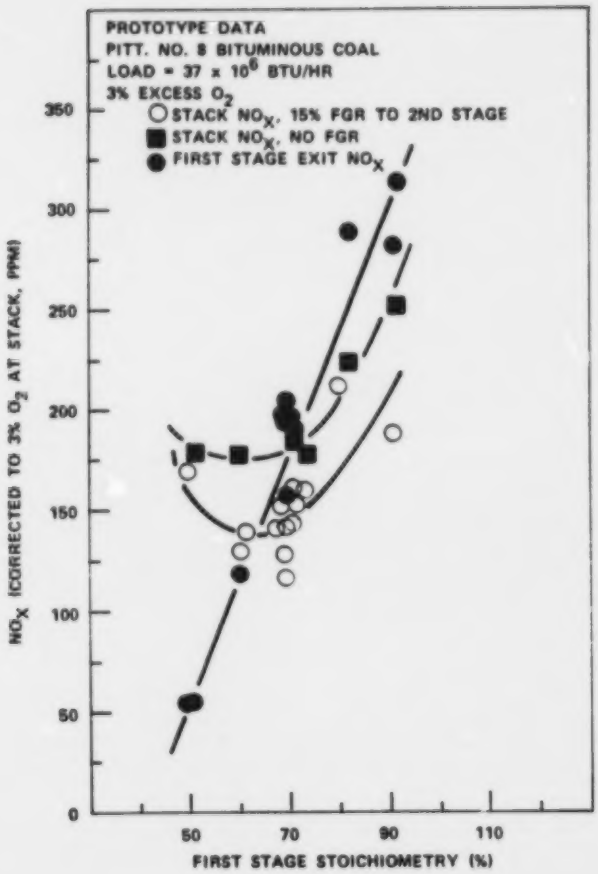


Fig. 4 Effect of first stage stoichiometry on NO_x – prototype system

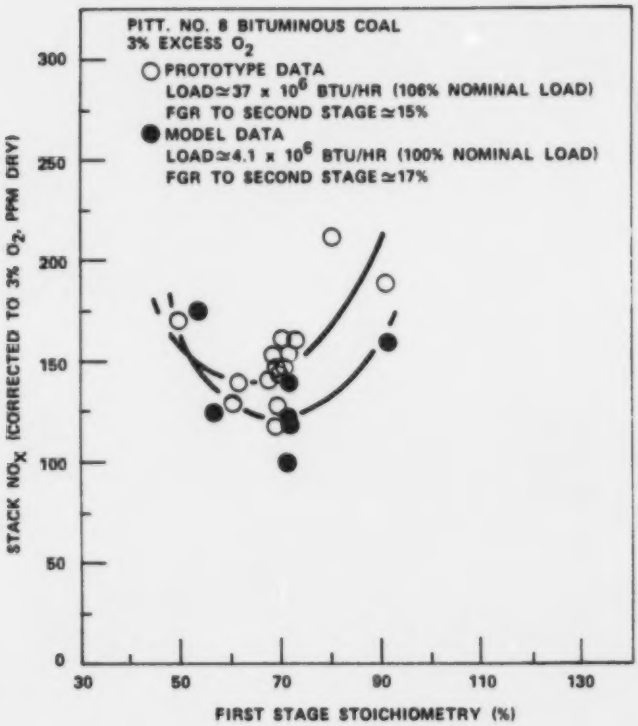
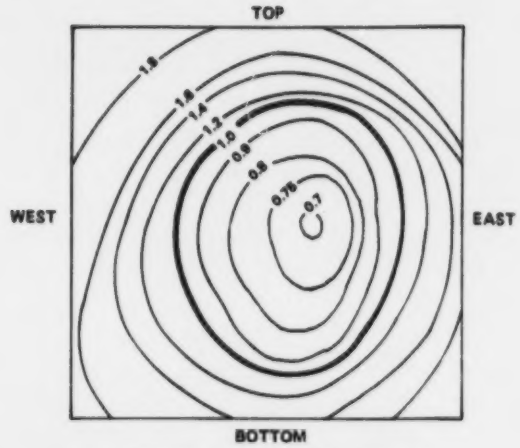
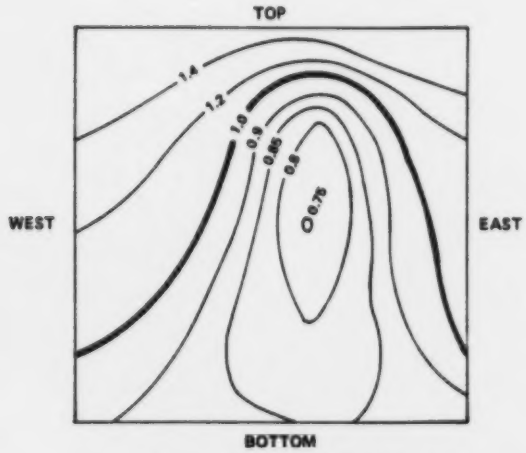


Fig. 5 Effect of first stage stoichiometry on NO_x – comparison of model and prototype data



PLANE 1, 4 FEET FROM BURNER



PLANE 2, 8 FEET FROM BURNER

Fig. 6 First stage flow patterns – prototype combustor

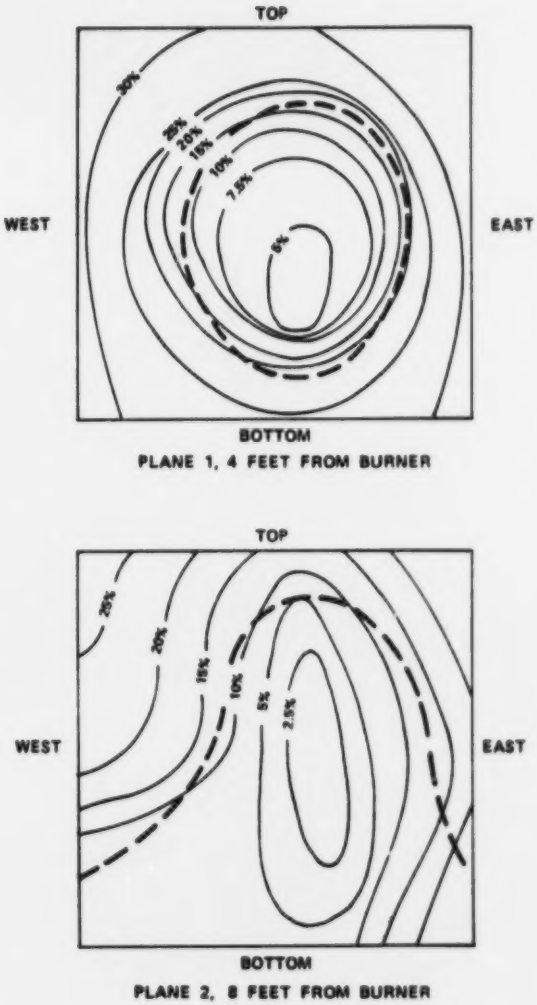
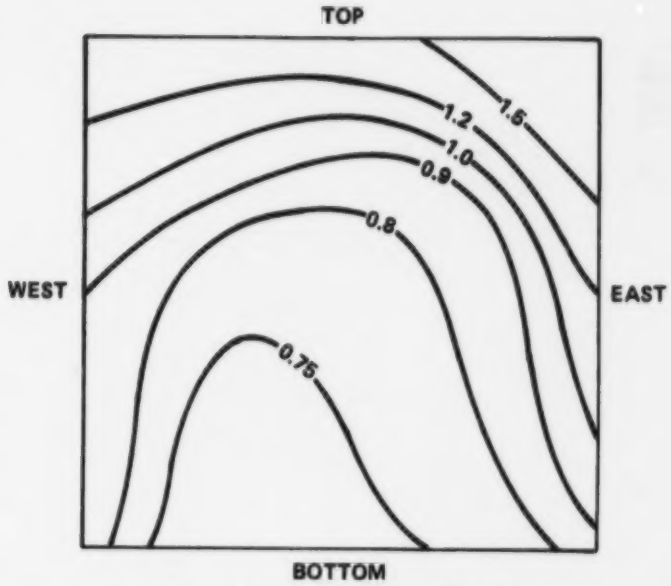
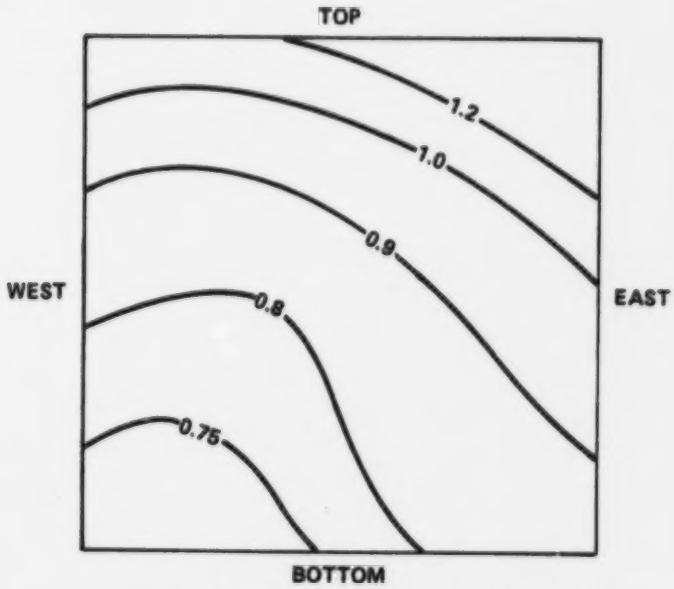


Fig. 7 First stage fuel N conversion – prototype combustor



PLANE 1, 4 FEET FROM BURNER



PLANE 2, 8 FEET FROM BURNER

FIGURE 8 GAS-PHASE STOICHIOMETRY PROFILES (RADIAL-VANE IMPELLER)

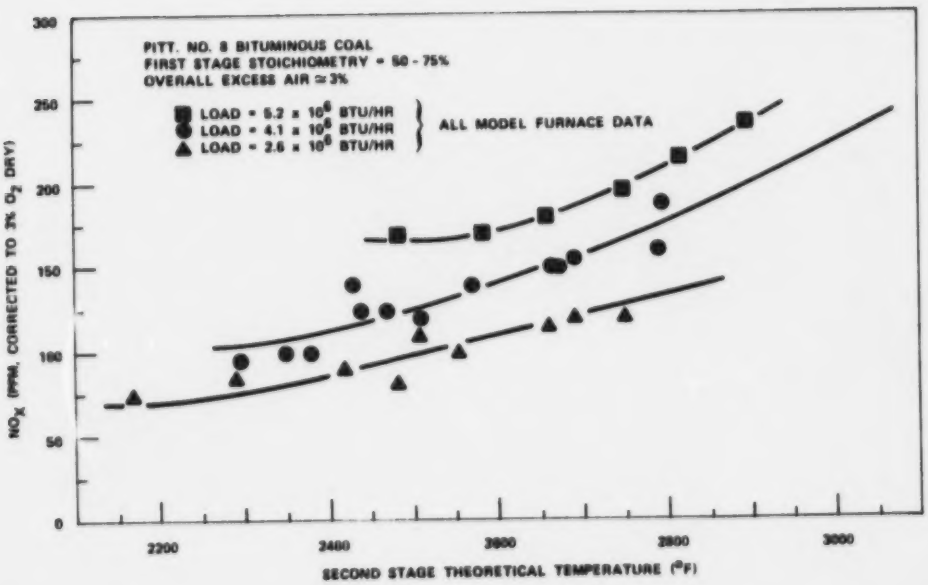


Fig. 9 NO_x emissions correlated against a calculated second stage temperature

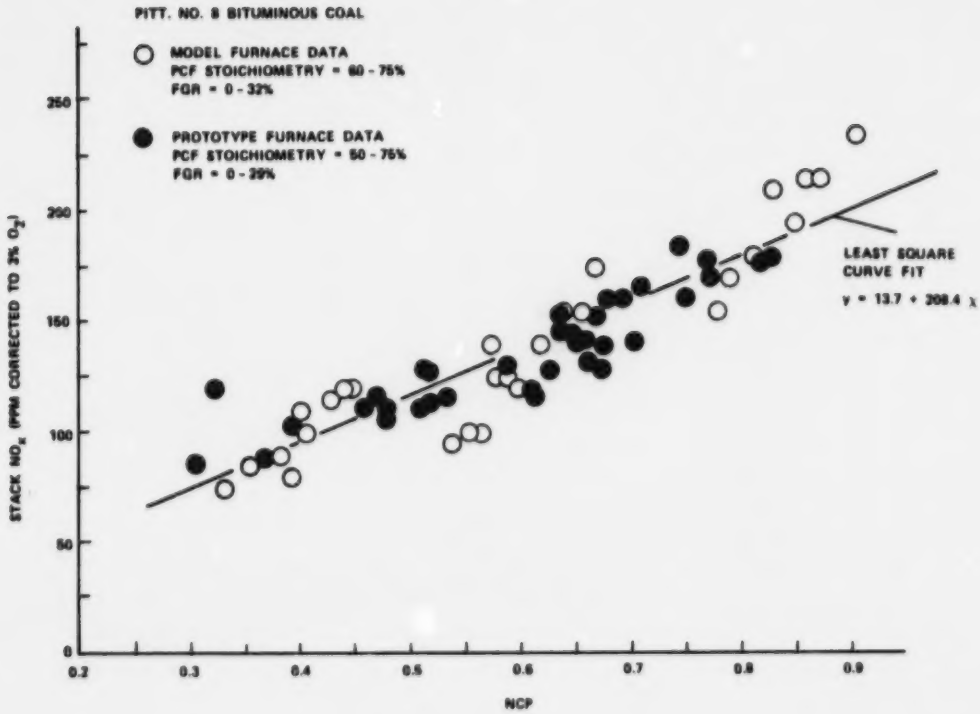


Fig. 10 NO_x correlation for Pittsburgh seam #8 bituminous coal

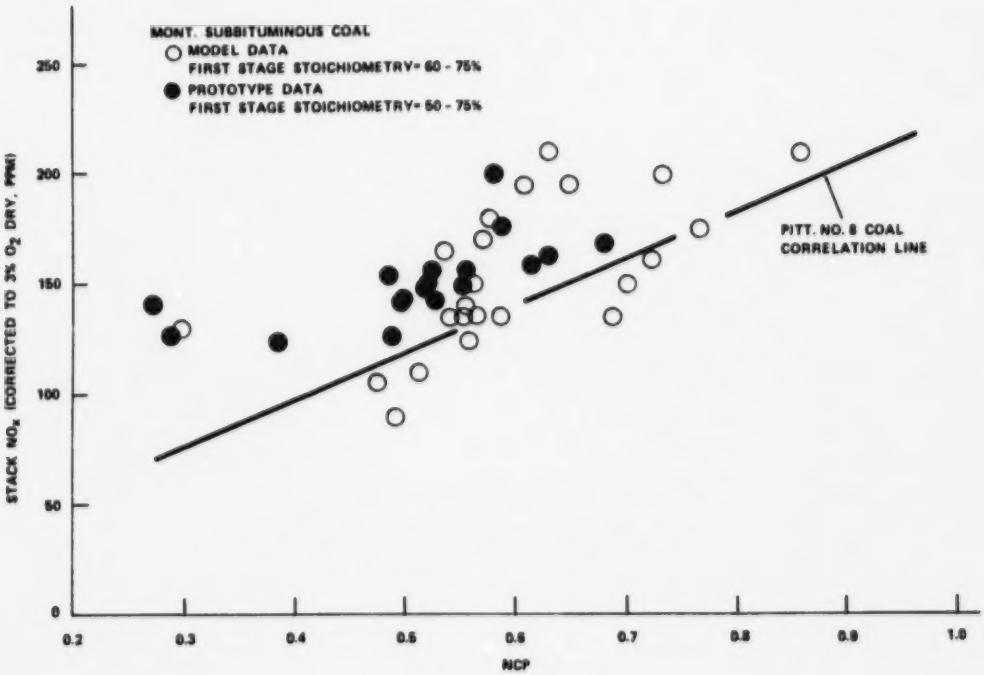


Fig. 11 NO_x correlation for Montana (Decker Seam) subbituminous coal

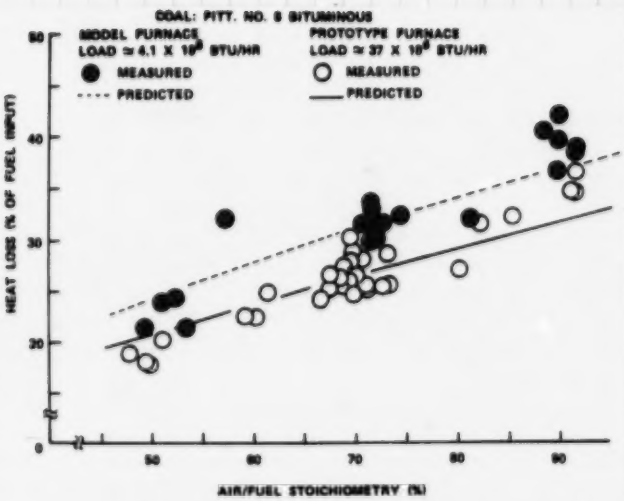


FIGURE 12 Comparison of actual and predicted heat removal

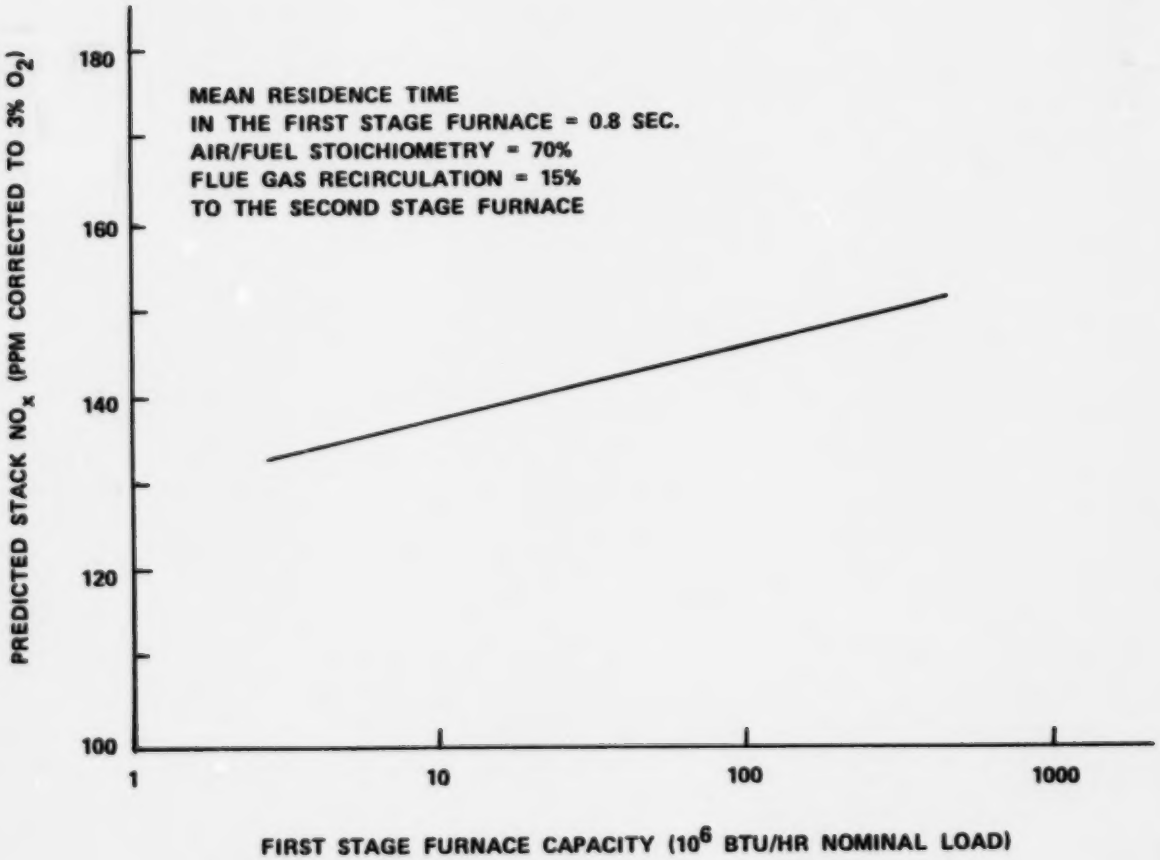


FIGURE 13 PREDICTED NO_x EMISSIONS (FULL SCALE PCF)

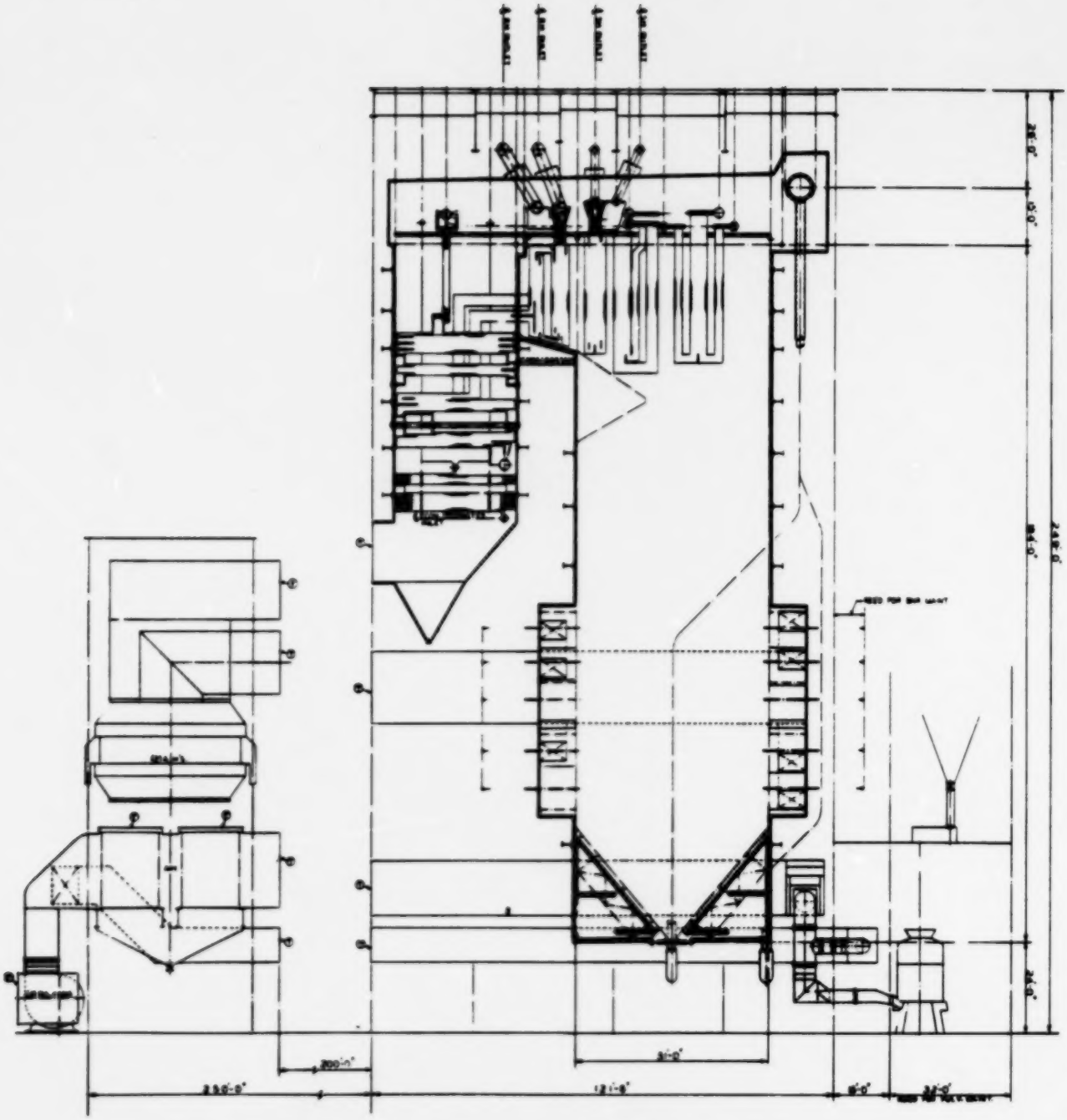


FIGURE 14 CONVENTIONAL FURNACE DESIGN

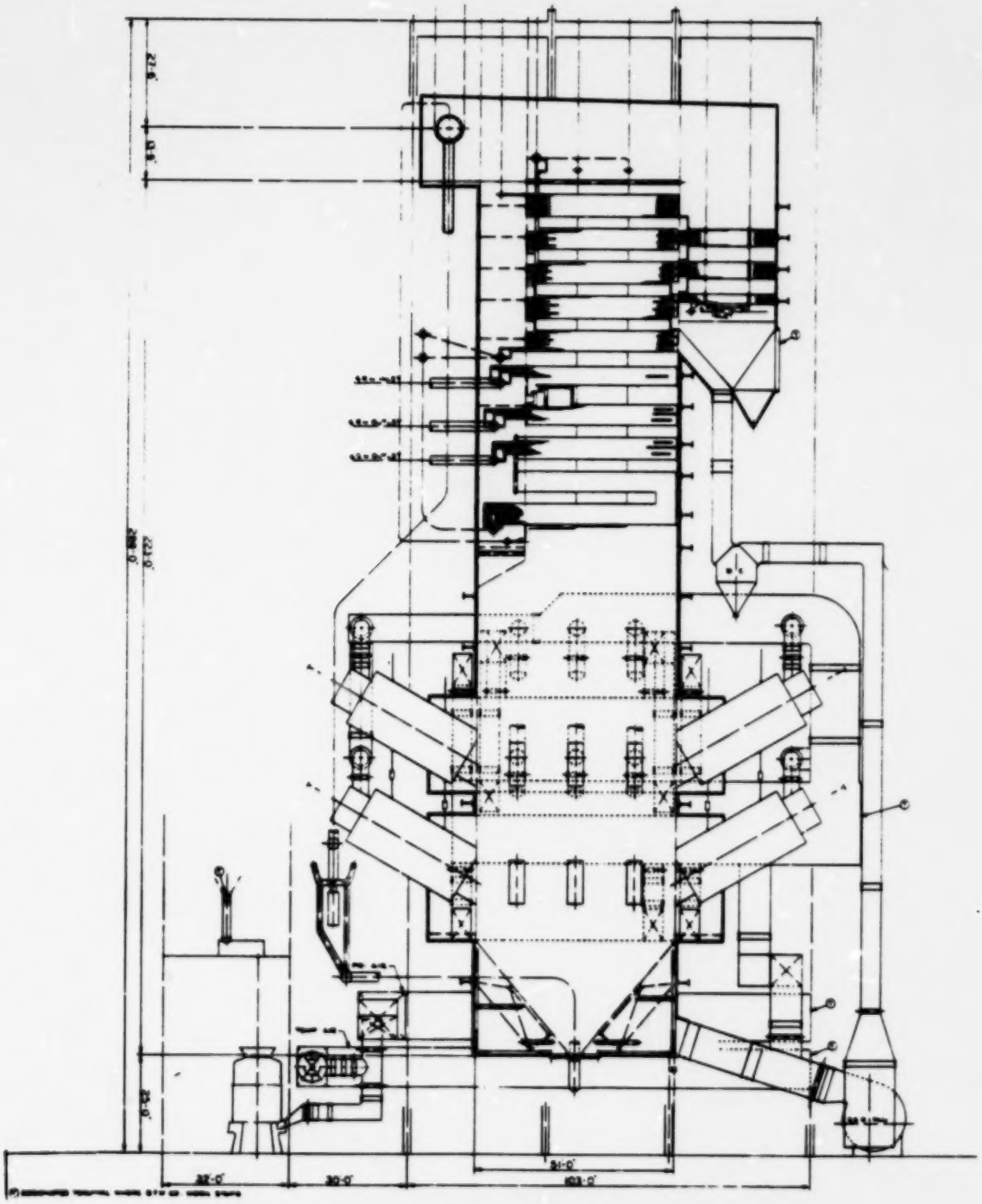


FIGURE 15 PRIMARY COMBUSTION FURNACE DESIGN

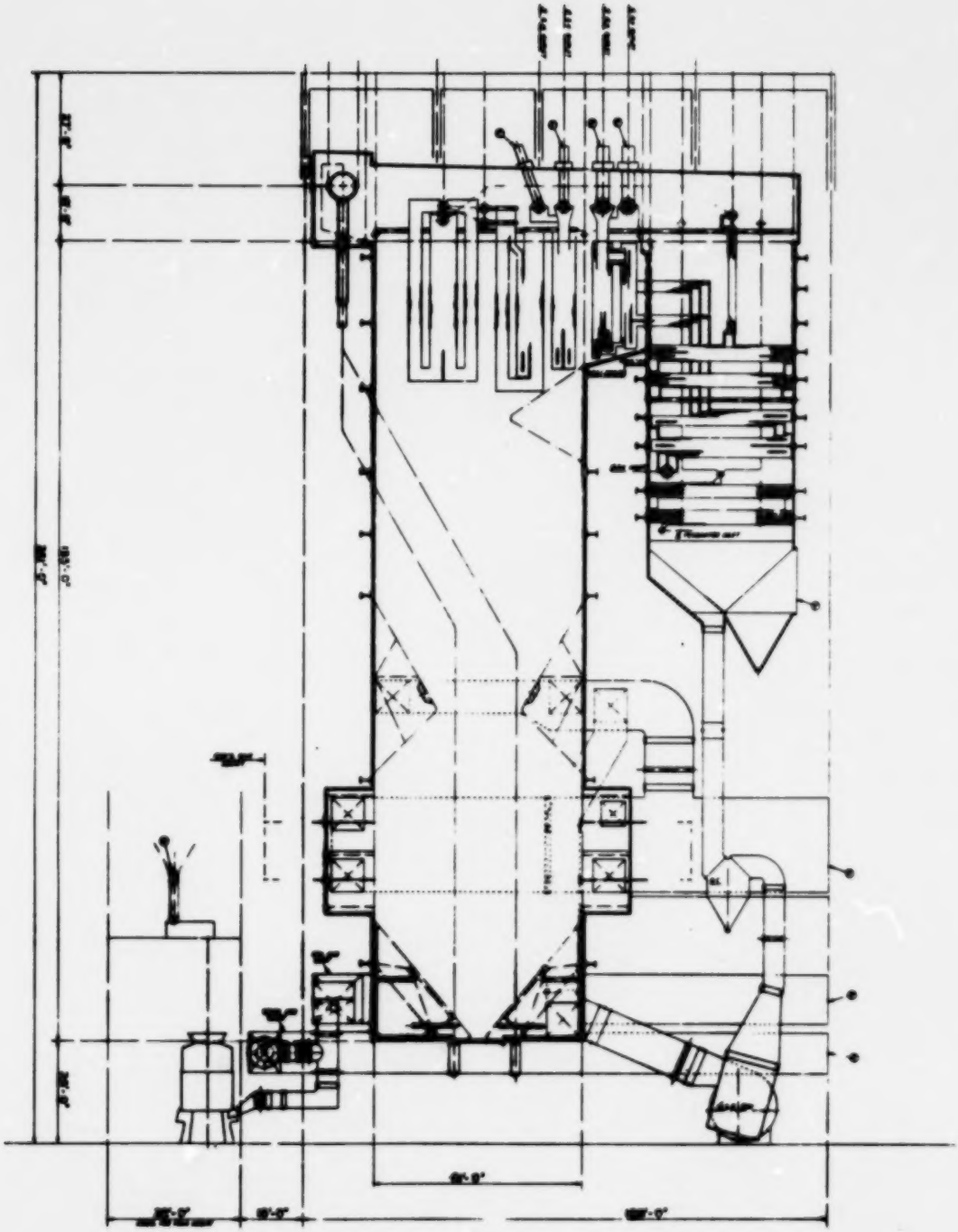


FIGURE 16 VENTURI FURNACE DESIGN

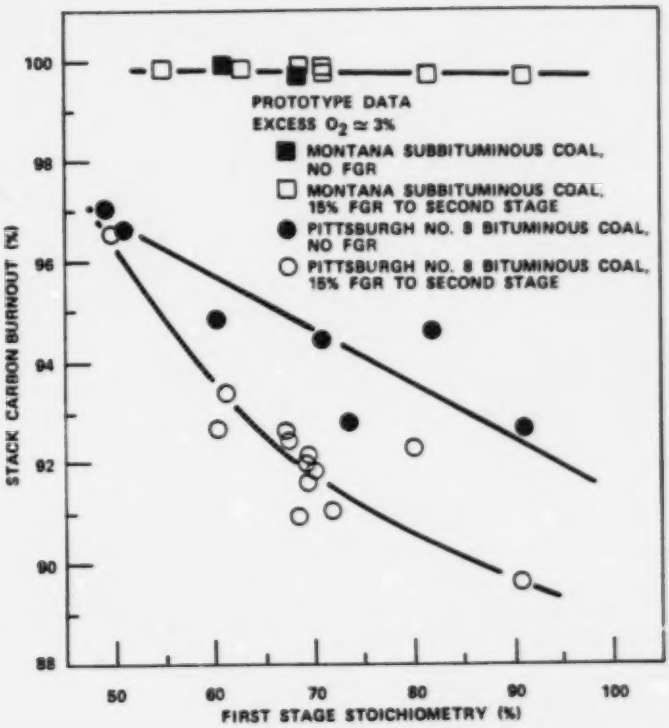


Fig. 17 Carbon conversion efficiency – prototype furnace

TABLE 1

Input Variable	Range of Applicability
First stage stoichiometry	60-75%
FGR	0-20%
Slot Angle	0-30%
Overall Excess O_2	2.5-3.5%
NCP	0.4-0.8

TABLE 2. COST-COMPARISON SUMMARY

Boiler Components	COST INCREASE (% OF CONVENTIONAL BOILER COST) Venturi Design	PCF Design
Pressure parts	5.5	8.0
Flues and Ducts	0.75	1.3
Structural Steel	2.25	6.6
Primary Furnaces	N/A	8.4
Circulation Pumps	N/A	4.7
	8.5%	29%

NOTE:
Percentages are based on a typical cost of $65/KW for the conventional boiler design, which can vary depending on scope, fuel, turbine heat balances, etc.

PILOT SCALE EVALUATION OF A LOW NO_x TANGENTIAL FIRING METHOD

By:

J. T. Kelly, R. A. Brown, J. B. Wightman
R. L. Pam, E. K. Chu
Acurex Corporation
Energy & Environmental Division
485 Clyde Avenue
Mountain View, California 94042

ABSTRACT

The Environmental Protection Agency (EPA)/Acurex 293 kWt pilot-scale facility was used to develop a low-NO_x pulverized coal-fired tangential system. Low NO_x is achieved by directing the fuel and less than 20 percent of the secondary combustion air into the center of the furnace with the remaining secondary combustion air directed parallel to the furnace walls. The separation of secondary combustion air in this manner creates a fuel-rich zone in the center of the furnace where NO_x production is minimized. This combustion modification technique has lowered NO_x 65 percent relative to conventional tangential firing. In addition, CO, UHC, and unburned carbon emissions are substantially unaffected by the modification. Also, the modification places a blanket of air on the furnace walls which is beneficial from a wall corrosion and slagging point of view. Finally, the modification shows a decrease in NO_x emissions as firebox gas temperature is increased. This characteristic might be beneficially applied in a large-scale system to reduce furnace volume, and thereby capital cost, for a given combustion heat release.

Tests are now underway to further optimize and characterize this low-NO_x combustion modification technique.

ACKNOWLEDGEMENTS

This work is supported by the EPA under Contract 68-02-1885. David G. Lachapelle is the EPA Project Officer. The assistance of Acurex staff, P. M. Goldberg and E. B. Merrick, in this study is gratefully acknowledged.

INTRODUCTION

Maintenance of ambient air quality in the United States requires the restriction of NO_x emissions from stationary combustion sources. Tangentially coal-fired utility boilers account for about half of the steam-electric capacity generated in the U.S. by coal-fired utility boilers and produce about 40 percent of the NO_x emissions attributed to coal-fired boilers (Reference 1). These significant NO_x emissions and the projected increase in the number of these boilers make them candidates for emission control development both in terms of retrofit and new boiler designs.

During the combustion of pulverized coal, NO_x is generated from the nitrogen chemically bound in the fuel as well as from the oxidation of atmospheric nitrogen. For typical bituminous coals, NO_x emissions from the fuel-bound nitrogen can be a significant fraction of the total (Reference 2). NO_x emissions have been shown to respond to combustion modification techniques that alter oxygen concentration, residence time, and temperature during combustion (Reference 3). Lowering the oxygen concentration surrounding the fuel, either locally by fuel/air stratification or globally by limiting the air flow in the combustion volume, shifts the fuel and atmospheric nitrogen emission reactions from predominantly NO_x formation to a balance between NO_x and molecular nitrogen formation (Reference 3). In addition, given sufficient residence time at oxygen deficient conditions, previously formed NO_x can be reduced to molecular nitrogen by homogeneous (Reference 4) and heterogeneous (Reference 5) catalyzed and noncatalyzed reactions.

Lowering peak temperature under excess air conditions decreases atmospheric nitrogen NO_x formation (Reference 6). However, under very fuel-rich staged combustion conditions, lowering first stage temperature can

increase NO_x (Reference 6). This is due to less fuel nitrogen being volatilized in the first stage and carrying over and being converted into NO_x in the oxygen-rich second stage.

Even though imperfectly understood, these basic relationships between system parameters and NO_x emissions have been employed to moderately reduce NO_x emissions from tangential as well as other types of utility boilers (Reference 7). Some combustion modification techniques, such as staged combustion, can lead to significant NO_x reduction. However, a major portion of the firebox is operated under reducing conditions, which is undesirable from a wall corrosion and slagging point of view. Significant further reductions in NO_x from tangentially-fired boilers under acceptable combustion conditions requires a better understanding of the combustion processes that control NO_x formation/reduction. Therefore, this study is separated into two phases. The objective of the first phase is to develop an understanding of the processes controlling NO_x formation/reduction in pulverized coal-fired tangential boilers. Using the results of the first phase, the objective of the second phase is to develop and demonstrate, in pilot-scale, low-NO_x combustion modification techniques that can be retrofitted to existing, or incorporated into new, tangential boiler designs.

DEFINITION OF COAL-FIRED TANGENTIAL SYSTEMS

Figure 1 illustrates the main features and flow patterns of a tangentially-fired boiler. Fuel and air are introduced into the furnace through rectangular registers located in the four corners. The bulk of the combustion air enters above and below the fuel jet as shown. The jets are nonswirling and fuel/air mixing is slow relative to burners used in wall-fired boilers.

The tangential alignment of the centerlines of the corner jets to the circumference of a circle in the center of the furnace promotes the formation of a large-scale vortex within the furnace. Ignition of the fuel is provided by impingement of hot burnt gases from laterally adjacent burners and large-scale internal recirculation of combusted gases. Because ignition occurs primarily on the vortex core side of the fuel jet, combustion is asymmetric in the horizontal plane.

In addition to providing ignition, jet impingement and vortex interaction help mix fuel and air to complete combustion. Partially burnt gases from lower burner levels sweep past and interact and mix with higher burner level fuel and air jets, helping to mix the fuel and air.

Pilot-Scale Combustion Facility

Figure 2 shows the EPA/Acurex pilot-scale facility used for the baseline and combustion modification testing during this study. This facility has been used to study various firing modes (tangential, front-wall-fired) and fuels (coal, oil, gas, coal-oil mixture, refuse-derived fuel) (References 6 and 8). The maximum firing rate is approximately 600 kWt. The firebox is a 99-cm refractory-lined cube attached to a 61-cm refractory-lined tower in which convective heat exchangers are placed. Volumetric heat release, overall residence time, and furnace exit gas

temperature are matched between pilot- and full-scale facilities. Also, burners and their placement in the firebox are patterned after full-scale tangential systems. During tests, NO, O_2, CO_2, CO, and UHC emissions are continuously monitored with particulate samples taken intermittently. Table 1 lists the continuous measurement instrumentation. A complete description of the facility is given in Reference 6.

The simulation of full-scale firebox flow patterns and mixing by the pilot-scale facility was evaluated by comparing water model flow and pilot-scale flow and flame patterns to corresponding full-scale results. In the comparison, similarities were found for (1) ignition standoff and character, (2) flame spreading angle from burners, (3) apparent jet centerline angle from corners, and (4) vortex size.

Baseline Test Results

Figure 3 compares the NO emission levels achieved by the pilot-scale facility at various excess air levels on several coal types to full-scale utility boiler levels. The pilot-scale results correspond well with the full-scale results. Matching of the NO trend with excess air is encouraging in that this, as well as the abovementioned comparison of flame patterns, may be an indication of the matching of mixing processes between the full- and pilot-scale systems.

During baseline testing the CO, UHC, and carbon loss emissions were small and comparable to full-scale system levels indicating that complete combustion is occurring in the pilot-scale facility.

JET AND VORTEX CHARACTERIZATION TEST RESULTS

To assist in the definition of NO emission control strategies, conventional tangential-fired tests were carried out to characterize the important processes to NO formation/reduction in this system and establish the effect of design variables on these processes. During the characterization tests, the facility was operated at baseline conditions. The fuel chosen for all combustion system definition and modification testing was Utah bituminous coal. The fuel properties are given in Table 2.

In-Flame Sampling Test Results

In-flame gas and solid samples were taken by a water-quenched probe at a variety of firebox locations to determine the relative importance of near-burner, jet interaction, and vortex zones (see Figure 1 for zone definitions) on NO processes. The probe quenches particle and gas reactions by injecting water directly into the sample stream at the probe entrance. A limited number of sampling locations 7.6 cm below, 26.7 cm above, and at the burner centerline were chosen to characterize near-burner, jet interaction, and vortex zones.

Figure 4 presents the as-measured NO, O_2, and CO_2 concentrations, respectively, at the fuel tube elevation superimposed on a plan view of the firebox. These results show that, near the burner face, minimum NO occurs in the center of the fuel jet, where the fuel is relatively unburnt, and peaks on the vortex core side of the jet. The peak NO levels occur in hot ignition zones observed during testing. These zones, defined as jet interaction zones in Figure 1, are created by the interaction and mixing of the fuel jet with hot combustion gases from the adjacent upstream corner burner. Since the fuel is only 60 percent burnt and has been in this zone less than 100 ms, most of the combustion and NO production in this zone can

be associated with the volatile components of the fuel. The bulk of the total net NO production occurs in this near-burner region.

Downstream of the burner face and just prior to the next burner interaction, O_2 and CO_2 concentrations are more uniform and the NO peak is not as pronounced. Oxygen concentrations are low and NO concentrations are high in this zone, and the net NO production is small. This zone is downstream of where the vortex was observed to significantly impact with and cause rapid mixing of the fuel and air jets. Burning in this zone and downstream is mostly char combustion.

Probing results 26.7 cm above the burner level show CO_2, O_2, and NO levels are relatively flat and consistent with furnace exit conditions. Very little net NO production occurs in this zone and solid samples show that only 10 percent of the fuel is unburnt at this level.

Staged combustion probing tests were run at a firebox stoichiometric ratio (SR) of 0.85 with an overall stack excess air level of 15 percent. As expected (Reference 6), staged combustion significantly lowered stack NO through reduction of prior-formed NO and lower conversion efficiency of fuel N to NO. Of greatest interest were the probing results presented in Figure 5, which showed that, near the burner face, the vortex core side NO formation peak was eliminated by operating the firebox fuel rich. Operating the active zone on the vortex side of the fuel jet under O_2-deficient conditions appeared to eliminate the peak NO formation leading to a low firebox burner elevation NO level which is even further reduced by decay processes occurring above the furnace burner elevation.

NO Dopant Test Results

Information on the NO reduction capability of various zones in the firebox was obtained by injecting NO dopant into the firebox. A ceramic injector tube 1.9 cm in diameter was used to distribute NO over roughly a horizontal line source 15 cm long. The NO flow in the injector was set at a level required to give 375 ppm in the stack for an inert injectant. Injection locations were chosen above, at, and below the burner centerline to assess the NO reduction potential of the near-burner and vortex zones probed earlier. NO dopant was also injected into the primary air/coal

supply line to assess the effect of the very-near-burner zone on NO reduction. Figure 6 presents, on a plan view of the furnace, the percent of NO dopant remaining in the stack for the indicated injectant locations. The percent remaining is found by subtracting the exit NO concentration without dopant from the measured doped level and dividing by the theoretical inert injectant concentration of 375 ppm. Conventional as well as staged combustion conditions at a first-stage SR of 0.85 were tested.

For conventional combustion conditions, injecting NO on the fuel jet centerline near the burner gives NO reduction efficiencies of 70 to 80 percent. Away from the burner and in the vortex, reducton efficiency is about 50 percent. In the active zone on the vortex core side of the fuel jet, explored in the probing tests, reduction is 94 percent. Below the burner level, NO reductions of 80 percent were measured whereas above the burner level reductions were small, being less than 13 percent.

Under staged combustion conditions, at a first-stage SR of 0.85, reductions at the burner elevation were better by a factor of two from the unstaged results, except at a single point for which no explanation can be given. Below the burner level, reductions observed were about the same as conventional unstaged reductions. Above the burners, the reductions were significantly better for the staged conditions.

These results show that NO is most effectively reduced if the NO is injected into the active combustion and peak NO production zone formed by the interaction of hot burnt gases and the fuel jet. In this zone, reaction is probably fast and addition of NO can drive the reactions from NO_x production toward a balancing of NO_x production and reduction. Another effective reduction zone is near the burner face at the burner elevation. In this zone, oxygen is not abundant and NO is reduced. Below the burner level, NO reduction is effective for both staged and unstaged conditions. Since reduction is not observed above the burner level for lean conditions, this indicates that NO injected below the burner centerline must get entrained and reduced in burner elevation flame zones.

TANGENTIAL BURNER CHARACTERIZATION TEST RESULTS

Different burner designs were tested to assess their impact on NO and to determine the relationship between burner design parameters and NO. Burner designs tested were limited to nonswirling slow mix designs such as those presently used in tangential systems. Compact intense flames produced by swirl burners are not compatible with tangential firing due to potential corner slagging and deposition problems.

Based on the probing test results and the known importance of O_2 availability in the fuel jet to NO (Reference 6), burner designs were tested where the exposure of the fuel jet to combustion air and the hot combustion gases that provide ignition was varied. Also, in some of these tests the relative position between the fuel and air was varied to operate the vortex side of the flame more fuel-rich. For the burner design tests, three conventional baseline burners firing on gas and one experimental burner firing on coal were used to generate a conventional tangential system vortex.

Figure 7 presents the NO results and the burner fuel and air port configurations tested. In the burner configurations given in Figure 7, the open circles correspond to the end view of the burner combustion air supply tubes and the filled circles represent the fuel supply tubes. The NO results are given as a function of temperature since baseline testing showed that NO increases with temperature. Also shown is the NO level when all four corner burners are operated on gas. The results are uncorrected for the dilution effect of the lower NO gas combustion products. Actual differences in NO due to coal burner alterations are greater than, by up to a factor of four, the differences appearing in Figure 7. Going from configuration 1 to 5, exposure of the fuel jet to hot combustion gases decreases. Configuration 1 is the fuel jet alone with all of the secondary combustion air distributed to the other three corner burners firing on gas.

The NO results in Figure 7 show that configurations 2 and 5 have, for a given temperature, the lowest and highest NO levels of all the burners tested. In configuration 5, the fuel jet is surrounded by combustion air and entrainment of hot combustion gases into the fuel jet is limited. Configuration 2 has the fuel jet located on the vortex core side of the furnace with the secondary air jets aligned in a vertical row behind the fuel jet. It was observed that configuration 2 had rapid ignition and burning compared to configuration 5.

Configuration 1, the fuel jet by itself, had the greatest exposure to hot combustion gases of all the configurations tested, and had NO results similar to conventional tangential burner type arrangements such as configurations 3 and 4. It was observed that the fuel jet by itself was heavily impacted by the vortex flow, and fuel jet spreading and mixing was extreme compared to other configurations.

FIREBOX MIXING TESTS

Burner configurations 2, 3, and 4 were tested for the effect of firebox mixing intensity and jet breakup on NO by varying the three gas burner firing rates while maintaining the coal burner at a constant 73 kW. Varying the gas firing rate changes the vortex strength and the turbulence intensity in the firebox, which alters the coal burner mixing.

Figure 8 shows the NO results for configurations 2, 3, and 4 for gas firing rates from 0 to 293 kW. At 0 kW gas firing, the vortex is absent and the burner flames are long and narrow. As the gas firing rate is increased, the firebox vortex develops and the coal flame begins to broaden somewhat near the burner face and bend slightly while ignition and burning increase on the vortex side of the fuel jet. An even more significant change in flame character with increasing gas firing rate is the strong impact and dispersion of the fuel jet about one-half the firebox length from the burner face. At this location, vortex interaction with the jet is significant enough to destroy the original collimated character of the coal jet and disperse the fuel in the firebox. This fuel dispersion in an overall oxygen-rich environment is detrimental to NO emissions. Figure 8 shows that the as-measured NO results do not change significantly for gas firing rates from 0 to 293 kW. However, these results are uncorrected for dilution by the considerably lower NO content gas burner combustion products. A simple correction for dilution would show a consistent and large (an estimated 900 ppm at maximum gas firing rate) increase of NO for the coal burner as the gas firing rate is increased. This demonstrates the importance of firebox mixing on NO.

The results in Figure 8 also showed the importance of the vortex to maintaining ignition and preventing lifted flames which have high NO. At 50 kW gas firing rate, or higher, ignition of the coal flame by the vortex

is very positive and the difference in NO between configurations is small. At 0 kW gas firing rate, where the vortex is absent and ignition is somewhat tenuous, configuration 4 experienced positive ignition at the burner face whereas configuration 3 did not and the flame became detached. This resulted in an increase in NO from the 200 to the 430 ppm NO level. This abrupt increase in NO has been observed elsewhere (Reference 11) for detached flames.

DISCUSSION OF TANGENTIAL SYSTEM CHARACTERIZATION RESULTS

Probing tests showed that, near the burner face, where the bulk of total NO is formed, combustion is asymmetric with ignition, intense burning and peak NO production occurring on the vortex core side of the fuel jet in the jet interaction zone. At this location approximately 60 percent of the fuel has been burned and this fraction can be associated primarily with the fuel volatiles. Fuel/air mixing in this zone is enhanced by the crossflow of hot combustion gases over the fuel and air jets. Since the initial fuel nitrogen volatiles see an abundance of oxygen in this zone, NO formation is very high (Reference 6). Lifted flame and dispersed fuel jet burner test results were extreme examples of how high O_2 concentrations at the fuel ignition point can lead to high NO. In addition, this zone has a high gas temperature, due to reduced wall heat transfer and high entrained combustion gas temperature. High temperature under O_2-rich conditions generates significant atmospheric nitrogen NO (Reference 6). NO dopant tests also showed that NO can be significantly reduced in the near burner zone, with the reduction most effective under fuel-rich combustion conditions. Adding NO in concentrated form to this very chemically active zone reduces some of the NO to N_2 even under overall lean conditions.

As shown by the staged probing and burner configuration tests, the high NO production rate of the jet interaction zone can be reduced by operating this zone fuel-rich through limits on fuel/air mixing. Under these conditions the volatilized fuel nitrogen will be in a more oxygen-deficient environment and the fuel nitrogen NO formation reaction will shift to a balance between NO and molecular nitrogen formation (Reference 3). Also, atmospheric nitrogen NO formation will be reduced under O_2 deficient conditions (Reference 3).

Downstream of the near burner zone, beyond roughly half the firebox length, the vortex interacts with the burner jets and causes the fuel and air to mix rapidly. Combustion and NO production in this zone and beyond are dominated by char burning and the net NO production is small relative to the near burner region. In this zone, the fuel nitrogen in the char matrix reacts in an environment that has a much lower O_2 concentration than the near burner region where the volatiles react. Also, previously formed NO concentrations in this zone are high. In this environment, NO reduction of the fuel nitrogen to molecular nitrogen can occur (Reference 3). In addition, previously formed NO can be reduced by homogeneous reactions with fuel components (Reference 4) or by catalytic and noncatalytic reactions on fuel particle surfaces (Reference 5). These processes together account for the small net NO production observed for this zone. Similar comments also apply to the above burner elevation zone.

Staged probing tests showed that operating the downstream burner zone fuel-rich causes decay of previously formed NO (References 4 and 5). In this environment the homogeneous and heterogeneous NO decay reactions discussed above overwhelm any NO production yielding low stack NO levels. The effectiveness of rich zones in decaying previously formed NO is also clearly demonstrated by the NO dopant tests. Reductions of up to 94 percent of the original dopant were observed when the combustor was operated fuel-rich at an SR of 0.85.

Based on burner flame observation and probing tests, the lower NO found for reduced firebox mixing is primarily due to the maintenance of locally rich zones downstream of the burner face where NO production from the char is minimized and previously formed NO decay is maximized. The same NO reduction processes that occur under globally rich conditions for staged combustion are active in the locally fuel-rich zones created by burner fuel/air stratification. Burner tests also showed that too low a mixing level can result in loss of ignition and lifted flames. These flames have high O_2 availability at the fuel ignition and volatile reaction point and thereby high NO.

LOW-NO_x SYSTEM

Based on the observations detailed in the last section, the requirements for a low-NO_x tangential system were identified. These are: (1) initiate burning sooner to minimize O_2 availability at the ignition point, (2) operate the jet interaction zone fuel-rich, (3) protect fuel jet from dispersion by vortex flow, (4) lower firebox mixing with the constraint of positive ignition, and (5) operate a portion of the char burnout zone oxygen-deficient to get NO decay. In addition to these low-NO_x requirements, constraints must be applied on the system relative to boiler size and efficiency, wall corrosion and slagging, and heat transfer. These constraints dictate that, to minimize corrosion and slagging problems, oxygen-deficient combustion gases should not contact the walls. Also, sufficient time and oxygen must be available to fully burn out the fuel and minimize carbon loss, CO, and UHC emissions. Finally, furnace volume and exit gas temperatures must be constrained to those typical of presently operating units.

Figure 9 presents a top and side view schematic of the low-NO_x system with rich and lean zones identified. The major system features are: (1) fuel directed at conventional tangential 6° yaw angle into the center of the furance, (2) some secondary air, either displaced toward the wall side of the firebox or surrounding the fuel jet, directed parallel to the fuel jet, (3) the bulk of the secondary air directed along the wall at and above the fuel jet elevation.

These major system features create oxygen-deficient conditions in the active near burner and the char burnout zone and fuel-lean conditions on the furnace walls at and above the fuel jet elevation. These system characteristics address both the low NO requirements and operational constraints noted above.

The initial low-NO_x system tests used a configuration that had variable wall air injection angles with respect to both the furnace wall and the horizontal plane. This configuration, denoted System 1, is shown schematically in Figure 10. The later testing used a configuration where all of the wall air jets were confined to the burner blocks set in the corners of the firebox. This configuration, denoted System 2, is also shown schematically in Figure 10. Though less flexible than the initial configuration, this later configuration is a closer representation of how the system might be retrofitted into a full-scale boiler. The primary emphasis of System 2 testing is to define the benefits of distributing the secondary combustion air over a wider elevation in the firebox than the initial testing. It should be noted that the true optimal low-NO_x configuration might occur when secondary combustion air is more uniformly distributed over the furnace wall than by the few discrete jets tested. However, the primary emphasis of this program is on retrofittable concepts that can achieve significant NO_x reductions without requiring major changes to tangentially-fired boiler hardware. This constrains the wall air introduction jets to the corners of the firebox.

System 1 Test Results

For System 1 testing, the corner burners in the pilot-scale facility were modified as shown in Figure 10 to simulate the low-NO_x system illustrated in Figure 9. Tests were then initiated to optimize the primary fuel, secondary and wall jet configuration, placement, direction and velocity. As shown in Figure 11, tests where the primary fuel and secondary jet configurations were varied showed that directing approximately 20 percent of the secondary combustion air into the center of the furnace and 80 percent along the walls at the fuel jet elevation gave the lowest NO for most of the System 1 primary configurations tested. For the fixed air jet area cases tested, increasing the percent air on the wall increases the velocity of the wall jet as well as distributes more of the air on the wall. The minimum NO levels may represent a balance between the benefits of the outward displacement of the combustion air, causing a wider separation of fuel and air, and the negative effects of increased fuel/air mixing caused by the higher velocity wall jets. Higher percentages of wall air than the optimal will give high wall air velocity and excessive mixing, and lower percentages

of air flow will place too much air in the center of the furnace, yielding nonoptimal results.

At 80 percent air on the wall, probing results showed that the center of the furnace is oxygen-deficient with this zone typically occupying 40 percent of the firebox at 20 cm above the burner level for most configurations tested. As the wall air mixes into this oxygen deficient zone it typically shrinks to 20 percent at 46 cm above the burner centerline. At this location, NO formation/reduction processes are essentially complete and NO levels are comparable to stack values.

Vicinity of wall oxygen concentrations are 10 percent at 20 cm above the burner elevation for the low-NO_x system versus 4 percent typical of conventional tangential firing in the pilot-scale facility.

Figure 3 shows the effect of excess air at the optimal 80 percent air on the wall for several primary configurations. As shown in Figure 3, the best configuration was a coannular primary/secondary air configuration. In this configuration the circular primary is surrounded by an annular passage that contains 20 percent of the secondary combustion air. Flame observation showed that this configuration had the smallest amount of fuel dispersion prior to entering the fuel-rich core zone. Various length slot primaries, though initially burning much sooner than the other configurations, had fuel dispersion problems. The dispersed fuel would burn in fuel-lean zones and yield high NO. Circular primaries having swirling or diverging flow also yielded higher NO at 15 percent excess air.

Figure 12 shows the effect of varying the wall air jet inclination angle on NO. The primary and secondary air jets for this case were similar to the configuration 2 jet locations shown schematically in Figure 7. At 0°, the wall air jet is behind the fuel jet and is shielded from the direct impact of the vortex flow. As the wall jet inclination angle is varied from the horizontal, the wall jet is directed out from behind the fuel jet which, due to the lack of fuel jet shielding, might be more easily entrained and mixed into the fuel-rich core. The decrease in fuel/air separation caused by this mixing might be the reason for the observed NO increase.

Besides yielding minimum NO, directing the wall air jet horizontally is desirable for multiburner level firing. For a system with several burner levels, directing the wall air upwards or downwards with respect to the fuel jet might result in undesirable burner to burner air jet interactions.

In addition to varying the inclination angle of the wall jets, one test considered the effect of directing the wall air at 10° away from the furnace wall. As shown in Figure 11, directing the wall air 10° off of the wall (configuration O) increased the minimum NO approximately 25 ppm over the 0° (configuration N) wall jet angle results. In addition, firebox probing tests showed that O_2 concentrations near the wall 20 cm and 46 cm above the fuel tube elevation were decreased for the 10° wall angle case. The higher wall O_2 concentrations and the lower minimum NO levels for the case where the air is directed along the wall makes this jet orientation the optimum.

Comparison of the best low-NO_x concepts results to conventional pilot- and full-scale tangential firing results in Figure 3 shows that the System 1 concept reduces NO emissions by roughly 60 percent and lowers the sensitivity of NO to excess air. This reduced sensitivity may be a result of the more diffusive burning nature of the fuel-rich core.

Combustion characteristics for the low-NO_x System 1 are not markedly different from conventional pilot scale tangential firing. Carbon monoxide, UHC, and percent carbon in flyash levels for this sytem are <36 ppm, <9 ppm, and <3 percent, respectively, versus conventional tangential firing results of <22 ppm, <1 ppm, and <7 percent. These NO reductions and good combustion efficiency are achieved while increasing vicinity of wall oxygen concentrations to 10 percent near the burner elevation. This oxygen blanketing of the wall is beneficial from a wall corrosion and slagging point of view.

An additional feature of the low-NO_x System 1 configuration is the improvement in NO emissions as temperature rises. Figure 13 shows that as gas temperature is increased for two different air-on-wall system configurations, NO decreases. As discussed earlier, under the fuel-rich conditions existing in the center of the furnace, increases in temperature

will lead to more volatilization of the fuel nitrogen in the rich zone and more conversion of this nitrogen to molecular nitrogen rather than to NO. This attractive emission behavior with temperature might be beneficially used to reduce boiler size and capital cost for a given heat release.

Also shown in Figure 13 is the NO reduction caused by decreasing load at a fixed gas temperature. As discussed previously, reducing load decreases firebox mixing thereby maintaining rich zones in which NO is minimized.

System 2 Test Results

The burner configuration used in System 2 testing is shown schematically in Figure 10. This system differs from the initial configuration in that four wall jets, instead of two, are used and these jets are confined to the corner burner blocks. This configuration more closely simulates the retrofitting of the low-NO_x concept into a full-scale tangential boiler. In addition, operating the four levels of wall air in this configuration defines the emissions and efficiency benefits of vertically distributing the combustion air.

Figure 14 presents the variation of NO levels with percent of secondary combustion air on the wall for the System 2 configuration. Each curve represents a different vertical distribution of air flow between wall air ports 1a, 1b, 2, and 3 as defined in Figure 10. The SR's achieved at each wall air level as a result of the vertical distribution of air is given in Figure 14. Configurations 1b and 1ab denote tests where air was flowing only in port 1b or air flow was equally split between ports 1a and 1b, respectively. Also included in Figure 14 are the optimal results from System 1 testing.

The cases where SR_1, SR_2, and SR_3 are 1.15 do not have wall air flowing in ports 2 and 3. Therefore, these cases are comparable to System 1 configurations where wall air ports 2 and 3 are absent. As shown in Figure 14, System 1 gives the lowest NO results and System 2, with only the 1B jet operational, gives the highest levels. The percent air on the wall at minimum NO falls between 80 and 85 percent for these cases.

Differences in wall jet configuration and location between these cases probably account for the differences in NO. As shown in Figure 10,

the wall jet for System 1 exits downstream of the corner, nearly half way down the furnace wall, whereas the wall jet exit for System 2 is in the corner. In addition, the wall jets in System 1 protrude into the firebox whereas the System 2 jets are confined to the corner burner blocks. These configurational factors can impact aerodynamics and mixing between the wall and fuel jets leading to the observed differences in NO. For example, the protruding wall jets may create separated flow zones in the firebox corners which help set up pressure fields to deflect the wall air away from the root of the fuel jets. This may reduce fuel/air mixing and benefit NO emissions. In addition, when only wall jet 1b is operating, the wall jet flow area is one-half that when 1a and 1b are working or when System 1 is tested. Therefore, the 1b test conditions represent very high wall air velocities as compared to the other cases. As discussed previously, higher velocities can lead to enhanced fuel/air mixing and thereby higher NO.

Even though System 2 NO results are marginally higher under these conditions, this configuration is preferred, since a retrofittable full-scale system simulation is more accurate with the System 2 configuration.

For both configurations 1a and 1ab the Figure 14 results show that, when wall air is distributed vertically to ports 2 and 3, NO levels decrease with the minimum NO point shifting to higher levels of percent air on the wall. In these cases, the vertical separation of the fuel and air is creating a larger and more fuel-rich zone at the fuel entry elevation where NO production is minimized.

Figure 15 shows the variation of configurations 1a and 1ab NO for a fixed percent air on the wall for a wide range of vertical distributions of wall air. These conditions were taken at a different temperature than the results in Figure 14. As can be seen in Figure 15, NO decreases for SR_1 less than 0.88, reaches a local minimum and then increases before finally achieving a second low level for the case where all of the wall air is evenly distributed between ports 2 and 3. As wall ports 1a, 1b, 2, and 3 air flow is varied, both the distribution and velocity of wall air is changing. For the 1ab case at the two extreme conditions, with no flow in wall air ports 2 and 3 and all of the air flow in ports 2 and 3, all of the jet velocities are equal and the observed NO reduction is due entirely to

the vertical displacement of wall air. Therefore, the results presented in Figure 15 under these extreme conditions show a distinct advantage in vertically separating the fuel and wall air. At intermediate air splits, the jet velocities are lower, which might be part of the reason for the local NO minimum. This point will be explored in further testing.

For application to real systems, conditions at SR_1=0.8 are more attractive than at SR_1=0.2. This is because at SR_1=0.8 significant amounts of wall air are present along the walls at and above the fuel tube elevation. Probing tests at the wall showed 15, 12, and 12 percent oxygen at, 20 cm, and 46 cm above the fuel tube elevation, respectively . Lower levels at the fuel tube elevation are expected for the SR_1=0.2 conditions. As indicated previously, maintaining a high oxygen concentration on the wall is beneficial from a wall corrosion and slagging point of view.

The minimum NO achieved with System 2 is lower than System 1 levels and represents a 65 percent reduction from baseline tangential system levels. Combustion efficiency during these tests was excellent with CO, UHC, and percent carbon in flyash emissions being less than 40 ppm, 3 ppm, and 2.4 percent, respectively. These levels are comparable to System 1 and conventional tangential system results.

CONCLUSIONS

Based on coal-fired and pilot-scale tangential system burner and vortex characterization tests, a low-NO_x system was defined. The major system feature is the dividing of the secondary combustion air between injection into the center of the furnace and injection along the furnace walls. The delayed mixing of the wall air into the vortex causes a rich combustion zone to develop in the furnace, minimizing fuel and atmospheric NO_x formation. Primary, secondary, and wall jet configurations and flowrates strongly influence the effectiveness of the system to lower NO_x emissions. Testing showed that the best results are achieved with (1) wall air directed horizontally and along the wall (2) wall air flow equal to or greater than 80 percent of secondary combustion air (3) primary/secondary air coannular configuration (4) wall air vertically distributed at and above fuel entry location. At optimal parameter settings, reductions of 65 percent in NO from conventional tangential system levels can be achieved at comparable combustion efficiency. In addition, wall oxygen concentration at the burner level is significantly increased over conventional tangential firing. This increase is beneficial from wall corrosion and slagging points of view. Also, the system shows a decrease in NO_x emissions as temperature is increased. This characteristic could be beneficially applied to reduce furnace volume for a given heat release.

REFERENCES

1. Lim, K. J., L. R. Waterland, C. Castaldini, Z. Chiba, and E. B. Higginbotham. Environmental Assessment of Utility Boiler Combustion Modification NO_x Control. Acurex Draft Report TR78-105, April 1978.

2. Habelt, W. W. The Influence of the Coal Oxygen to Nitrogen Ratio on NO_x Formation. Presented at 70th Annual AIChE Meeting, November 13-17, 1977, New York, New York.

3. Macek, A. Seventeenth Symposium (International) on Combustion, The Combustion Institute, 1978, p. 65,

4. Wendt, J. O. L., C. V. Sternling, and M. A. Matovich. Fourteenth Symposium (International) on Combustion, The Combustion Institute, 1973, p. 897.

5. Gibbs, B. M., F. J. Pereira, and J. M. Beer. Sixteenth Symposium (International) on Combustion, The Combustion Institute, 1976, p. 461.

6. Brown, R. A., J. T. Kelly, and P. Neubauer. Pilot Scale Evaluation of NO_x Combustion Control for Pulverized Coal: Phase II Final Report. EPA-600/7-79-132, Environmental Protection Agency, June 1978.

7. Breen, B. P. Sixteenth Symposium (International) on Combustion, The Combustion Institute, 1976, p. 19.

8. Brown, R. A. and C. F. Busch. Pilot Scale Evaluation of Waste and Alternate Fuels: Phase III Final Report. EPA-600/7-80-043, Environmental Protection Agency, March 1980.

9. Selker, A. P.: Program for Reduction of NO_x from Tangential Coal-Fired Boilers, Phase II and IIa. EPA-650/2-73-005a and b, Environmental Protection Agency, June 1975.

10. Crawford, A. R., et al. The Effect of Combustion Modification on Pollutants and Equipment Performance of Power Generation Equipment. EPA-600/2-76-152c, Environmental Protection Agency, September 1975.

11. Pershing, D. W. and J. O. L. Wendt. Sixteenth Symposium (International) on Combustion, The Combustion Institute, 1976, p. 389.

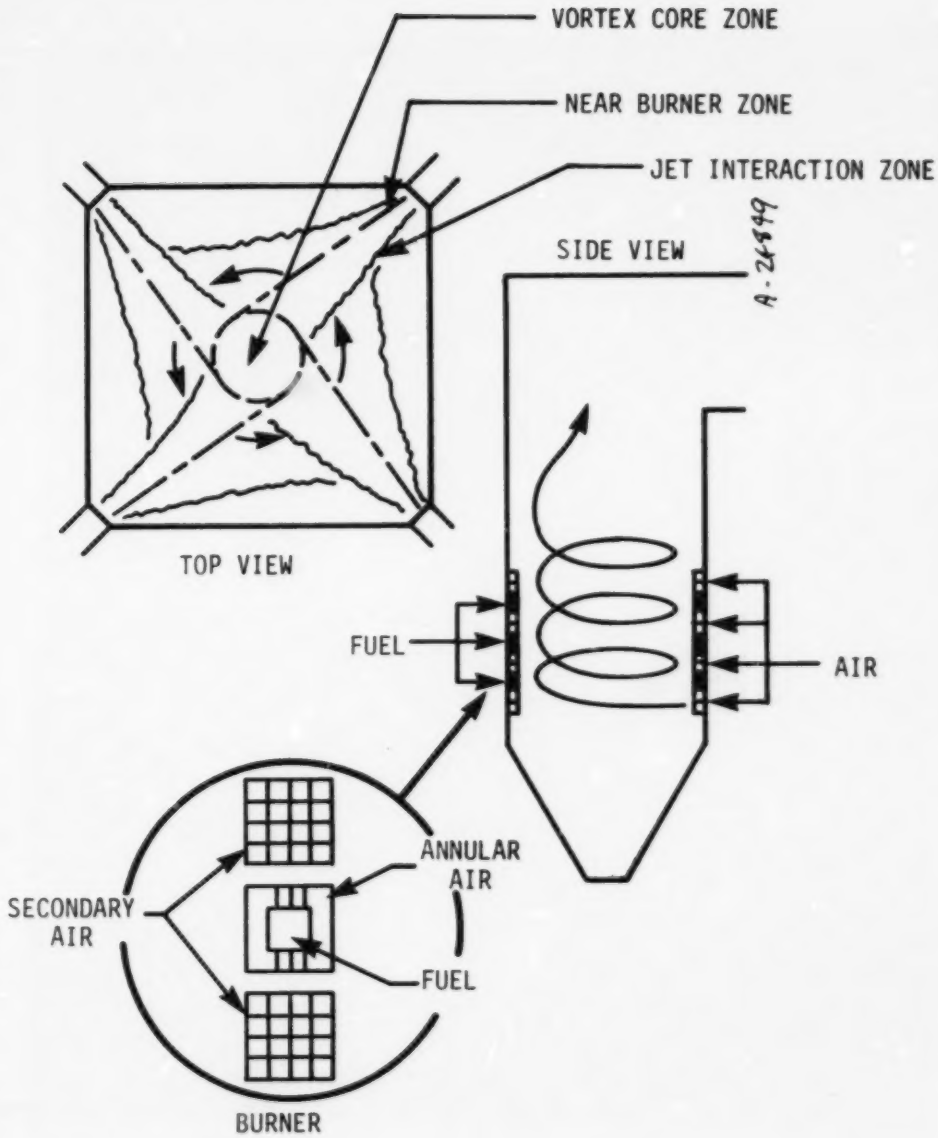


Figure 1. Tangential boiler schematic.

1. Combustion chamber
2. Ignition and flame safeguard
3. Observation ports
4. Ashpit
5. 440 kW swirl burner for front wall firing
6. Corner burners for tangential firing
7. 2033K refractory
8. Tower sections
9. Heat exchanger assemblies
10. Staged air injection ports

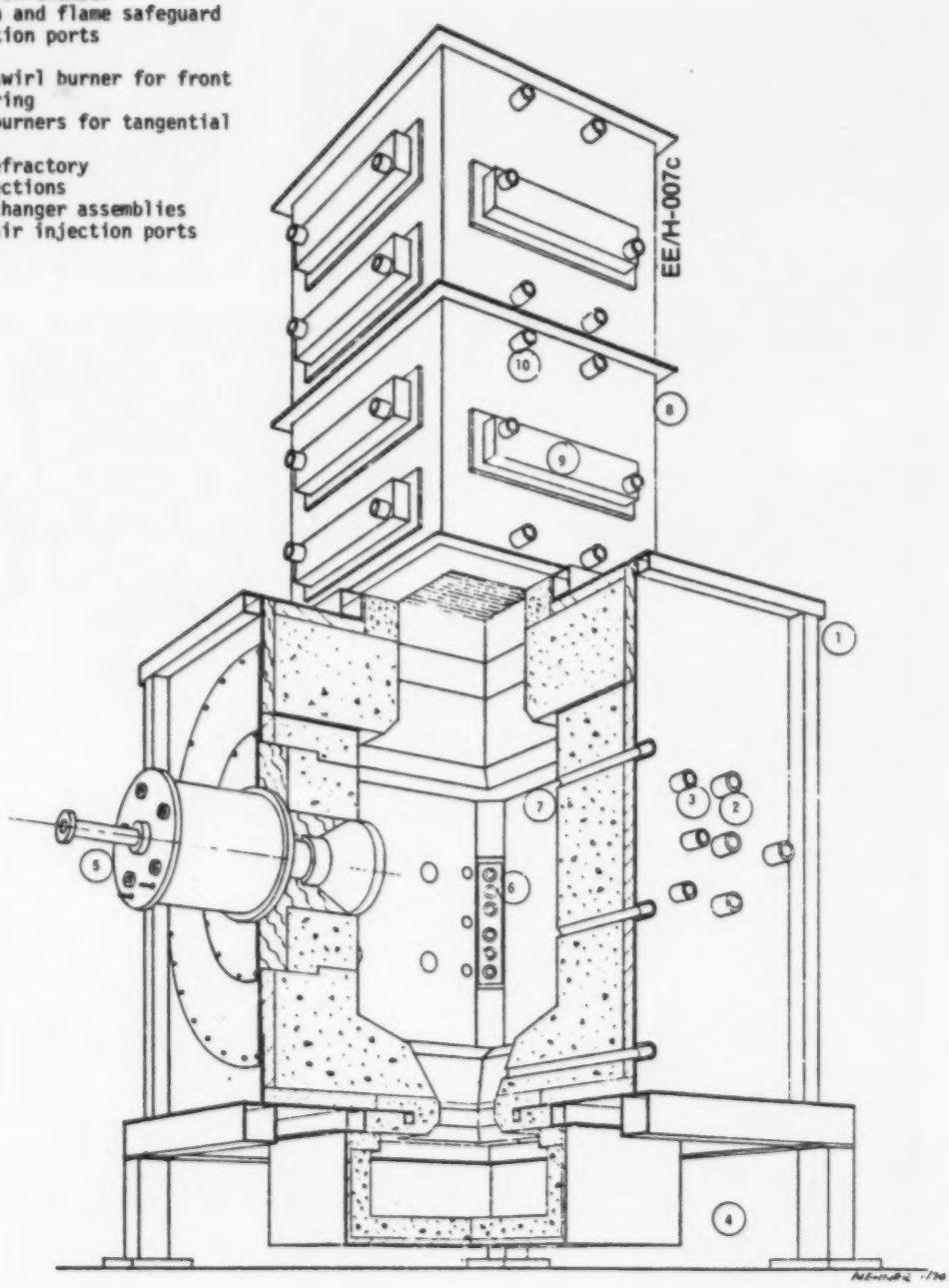


Figure 2. Pilot-scale test facility.

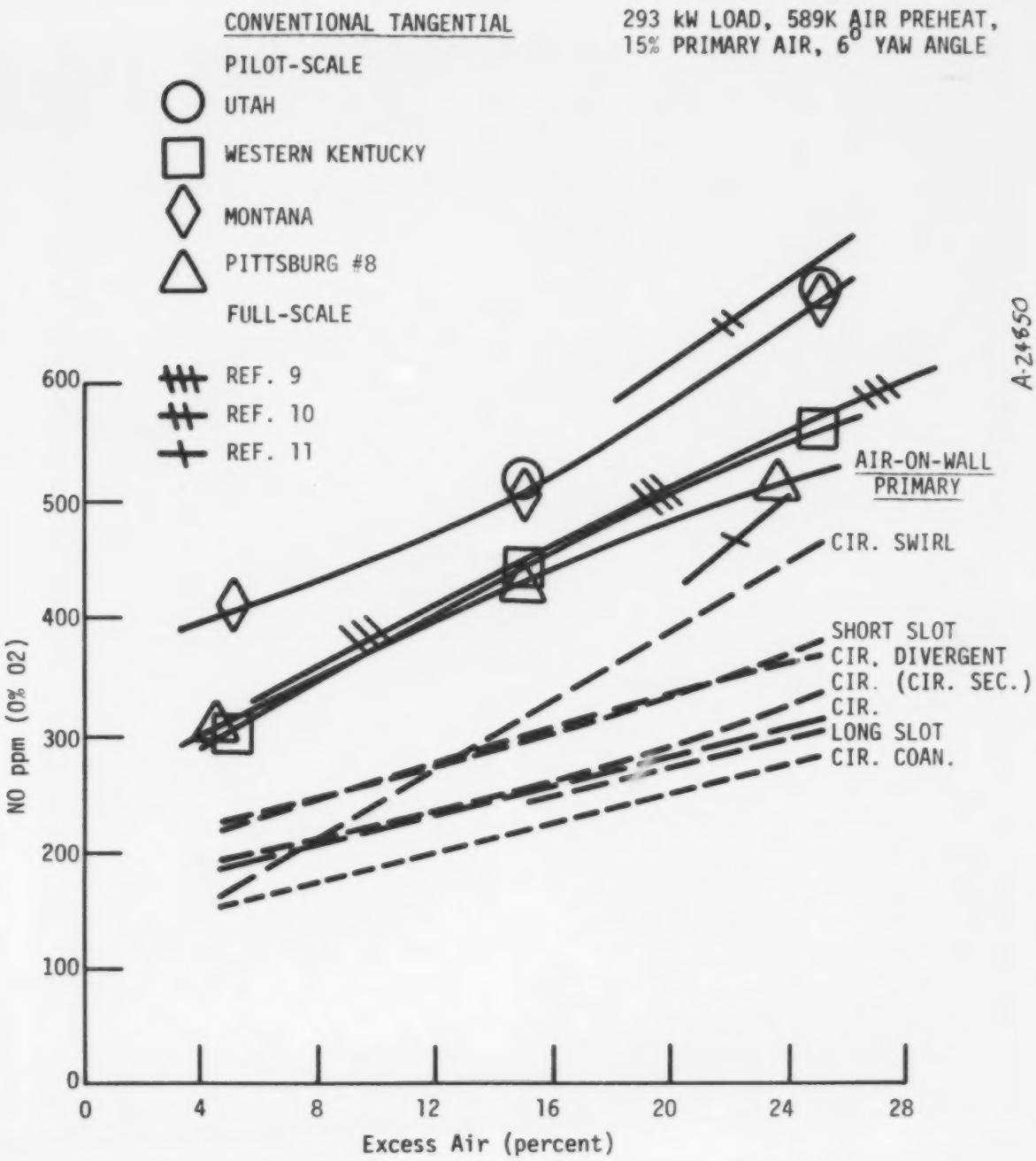


Figure 3. Effect of excess air on pilot-, full-scale and air-on-wall system NO emissions.

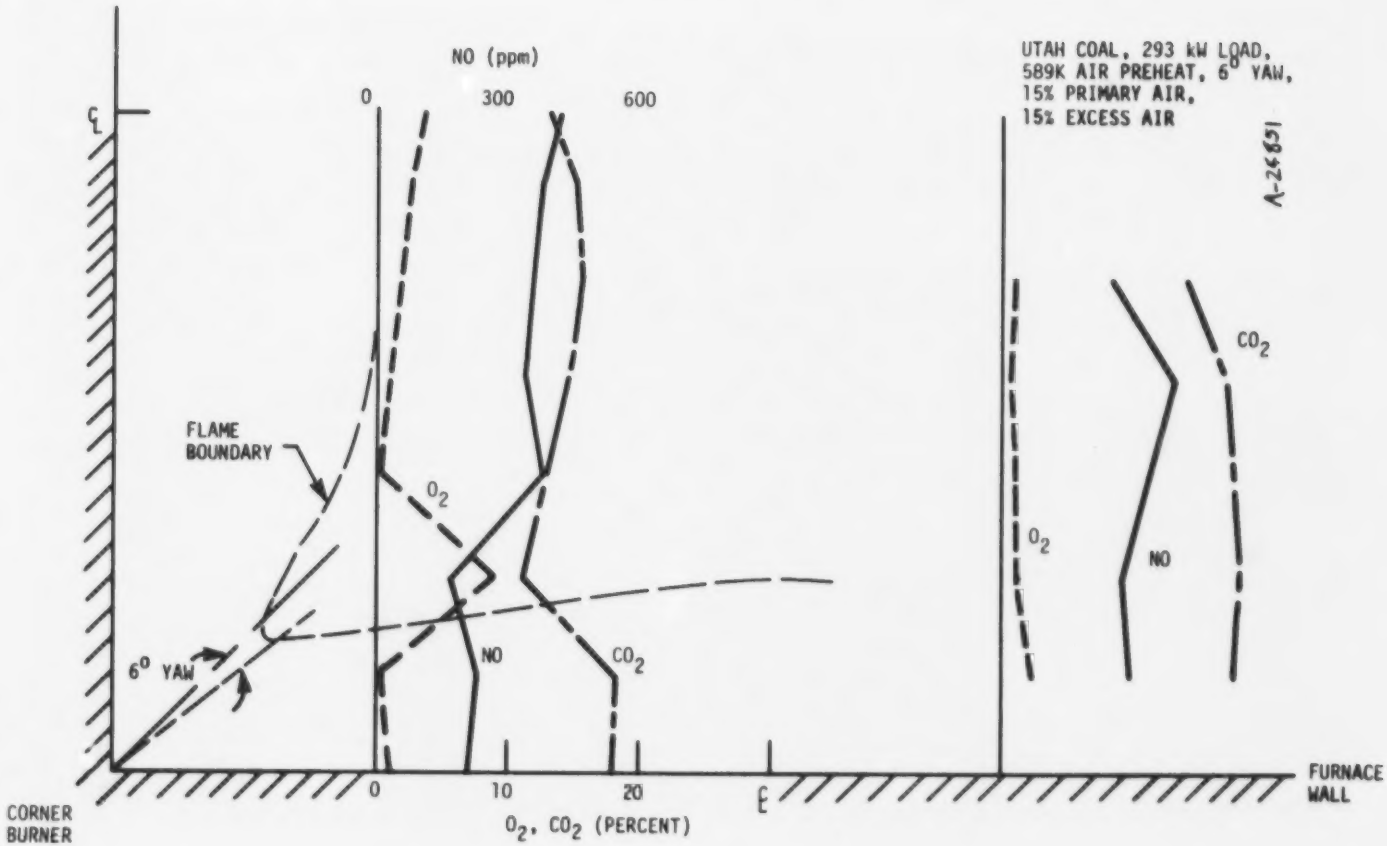


Figure 4. Concentration distributions at the fuel tube elevation superimposed on a plan view of the firebox.

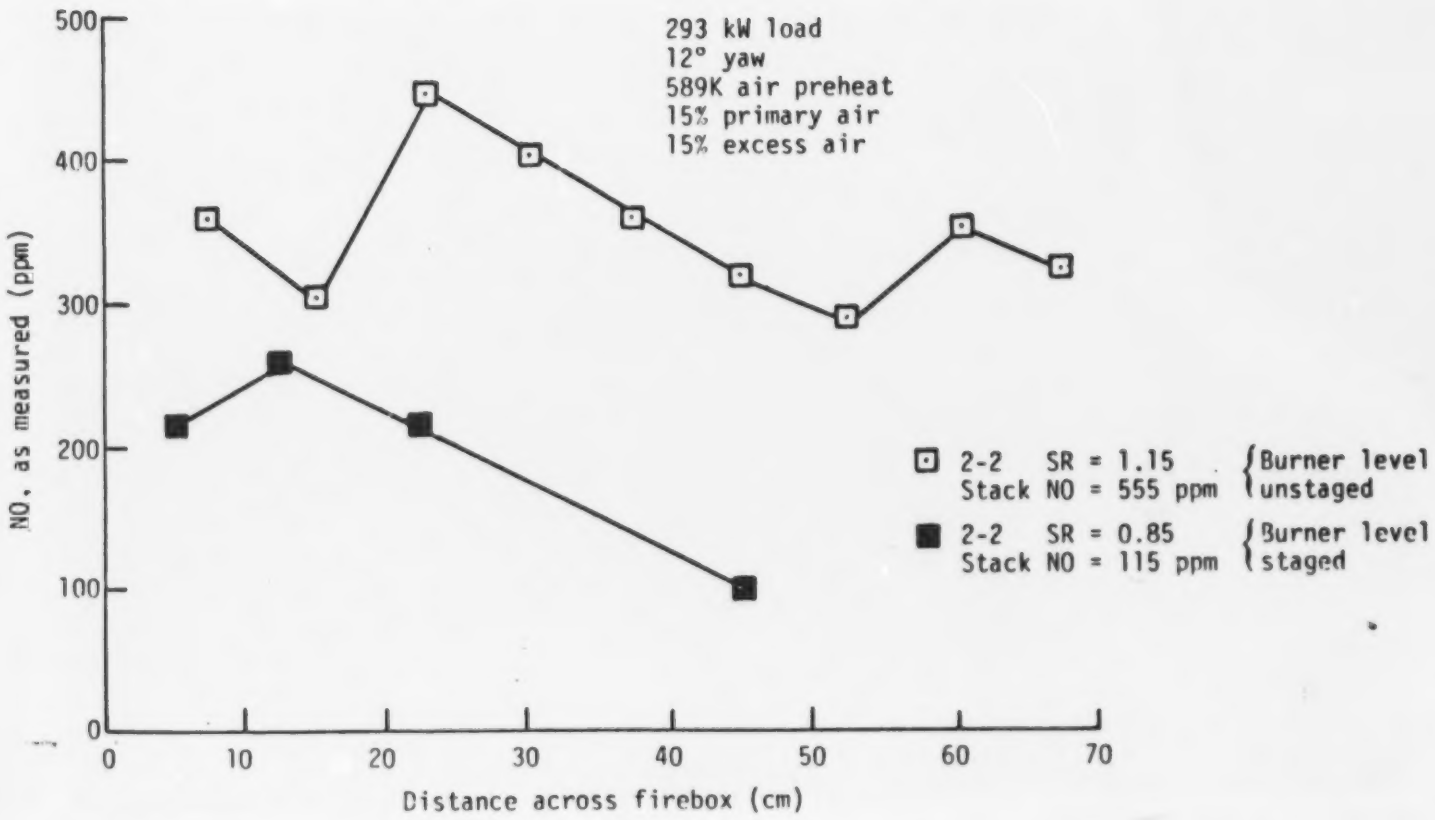


Figure 5. Comparison of unstaged and staged firebox NO probing results.

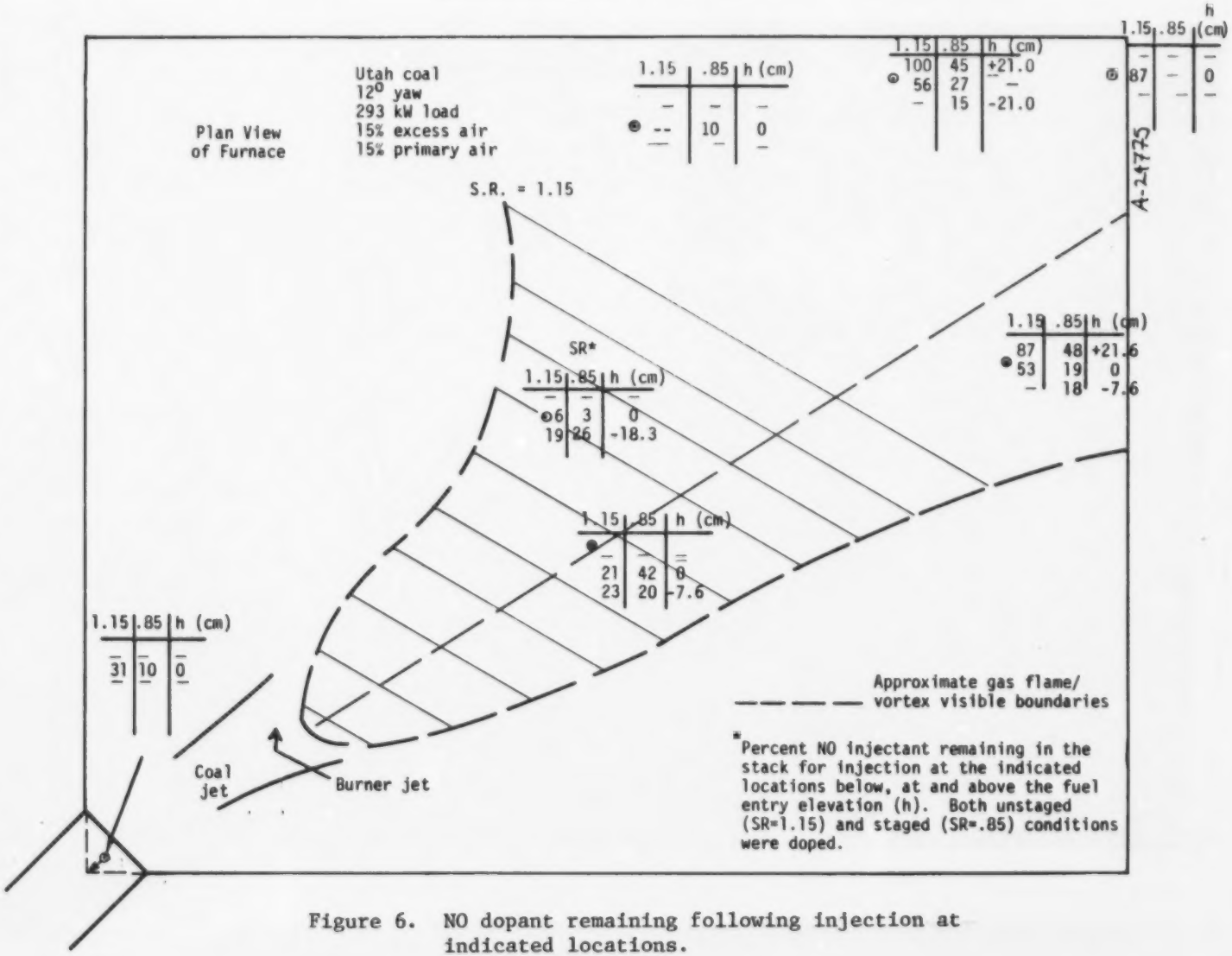


Figure 6. NO dopant remaining following injection at indicated locations.

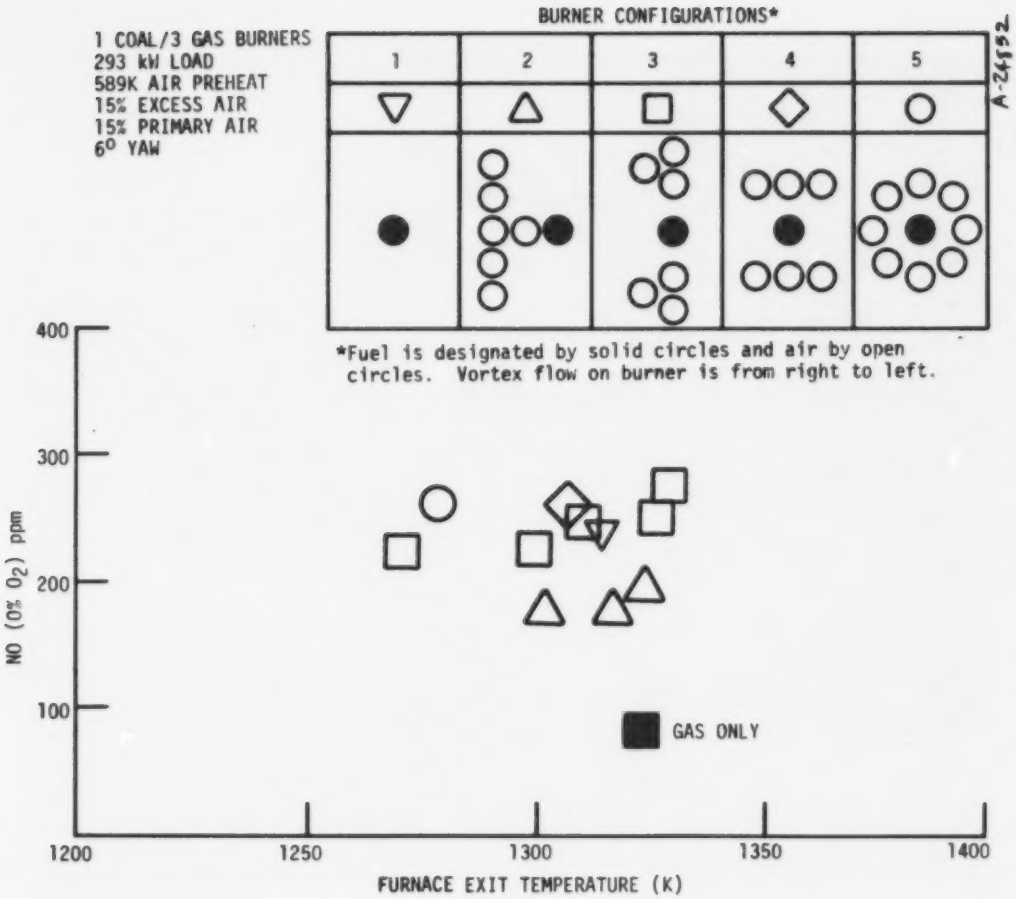


Figure 7. Burner configuration NO levels.

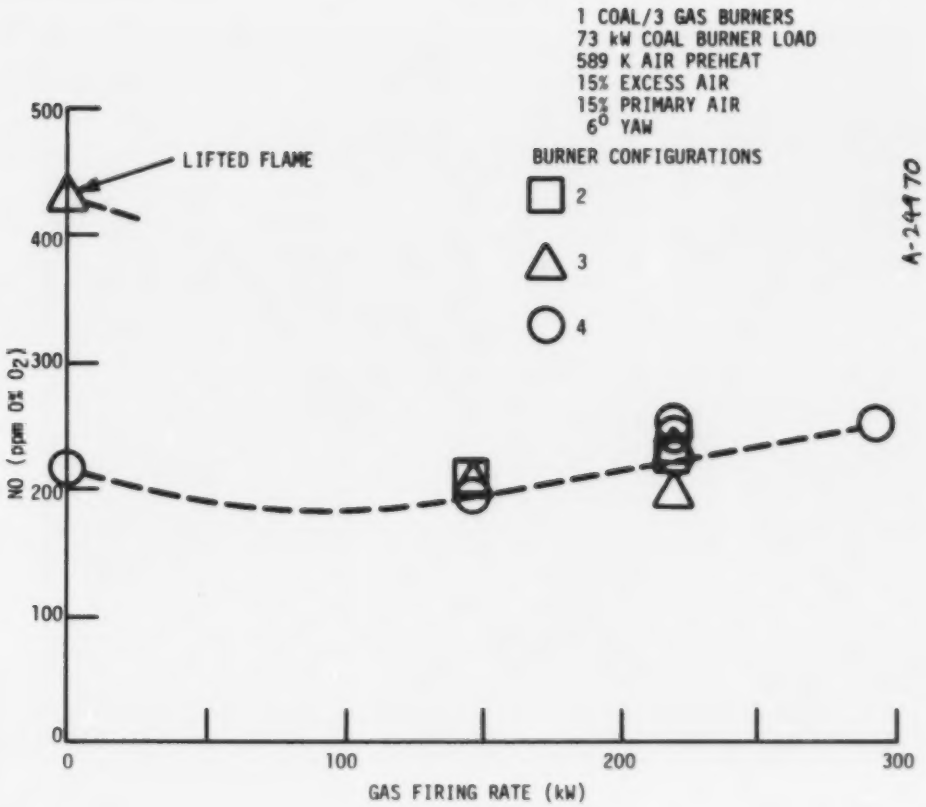


Figure 8. Burner configuration NO level variations with firing rate.

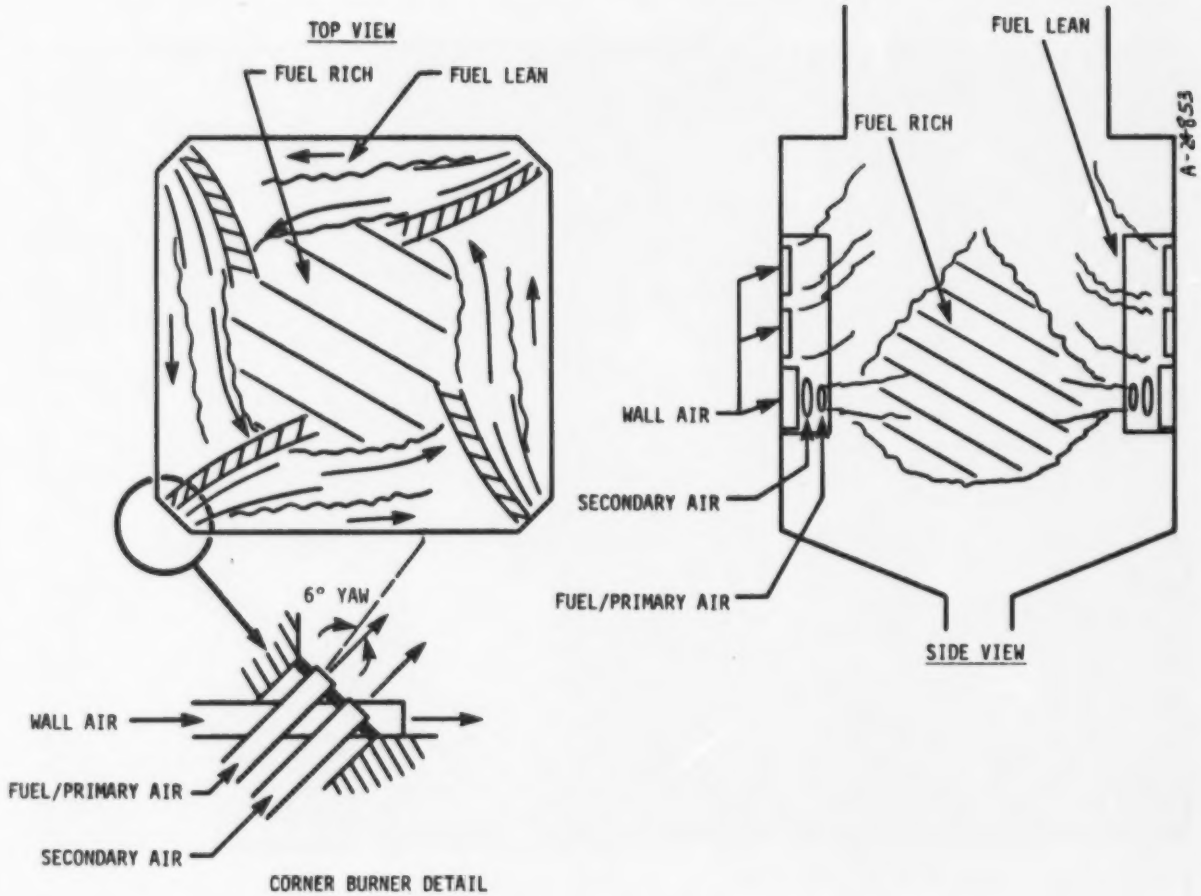


Figure 9. Low-NO_x air-on-wall system schematic.

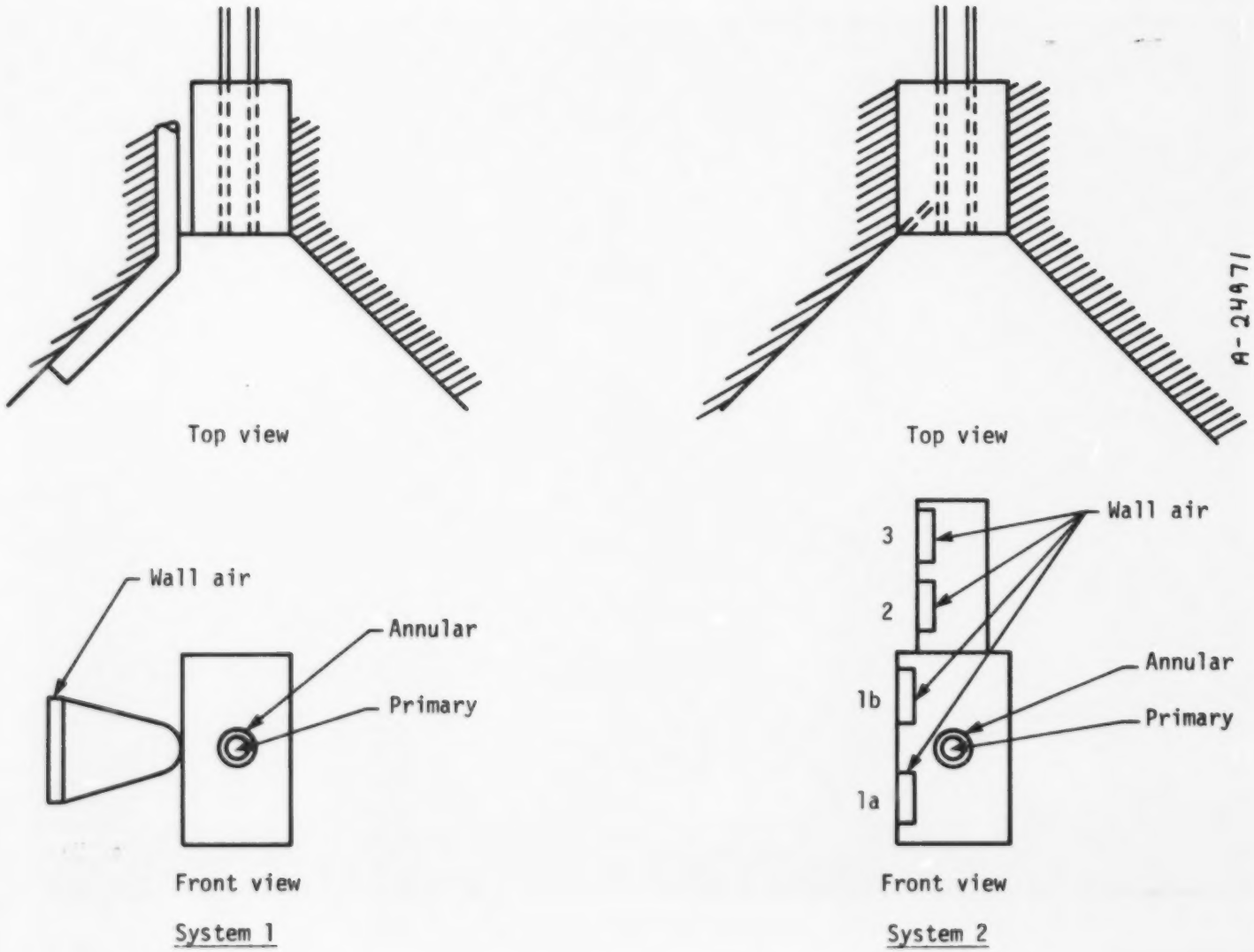


Figure 10. Low-NO_x system burner types.

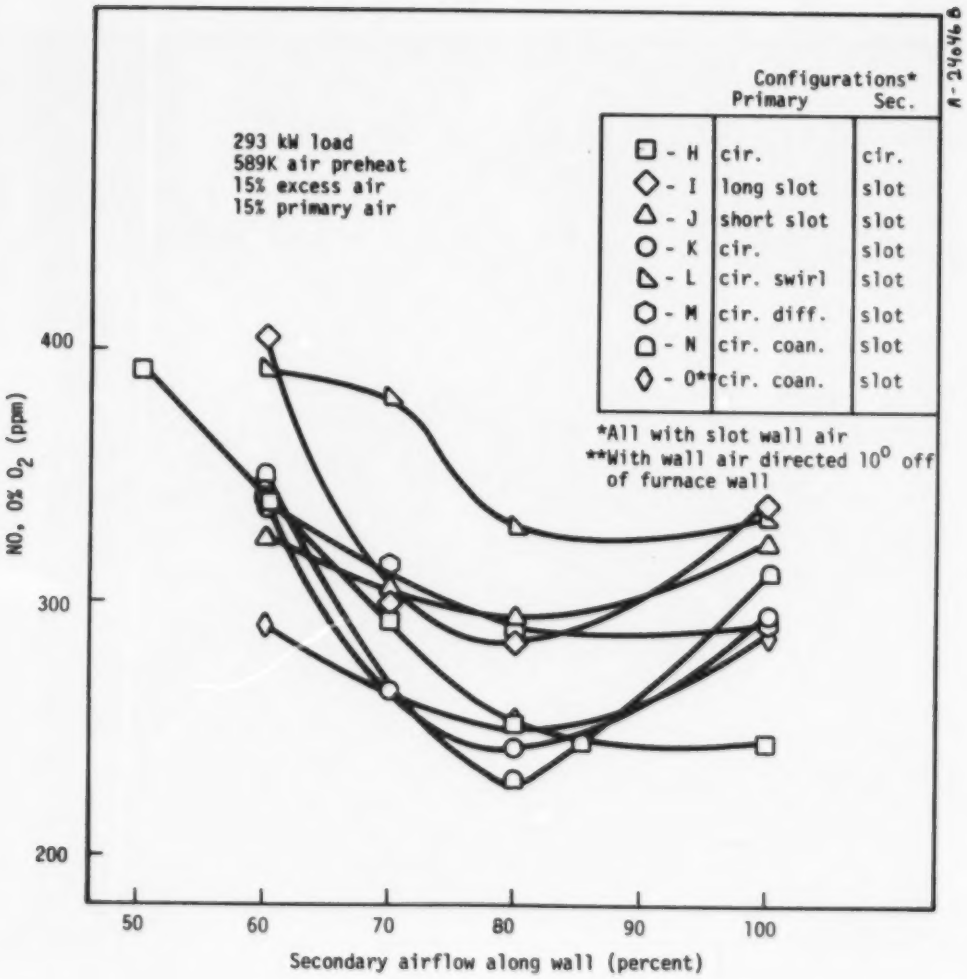
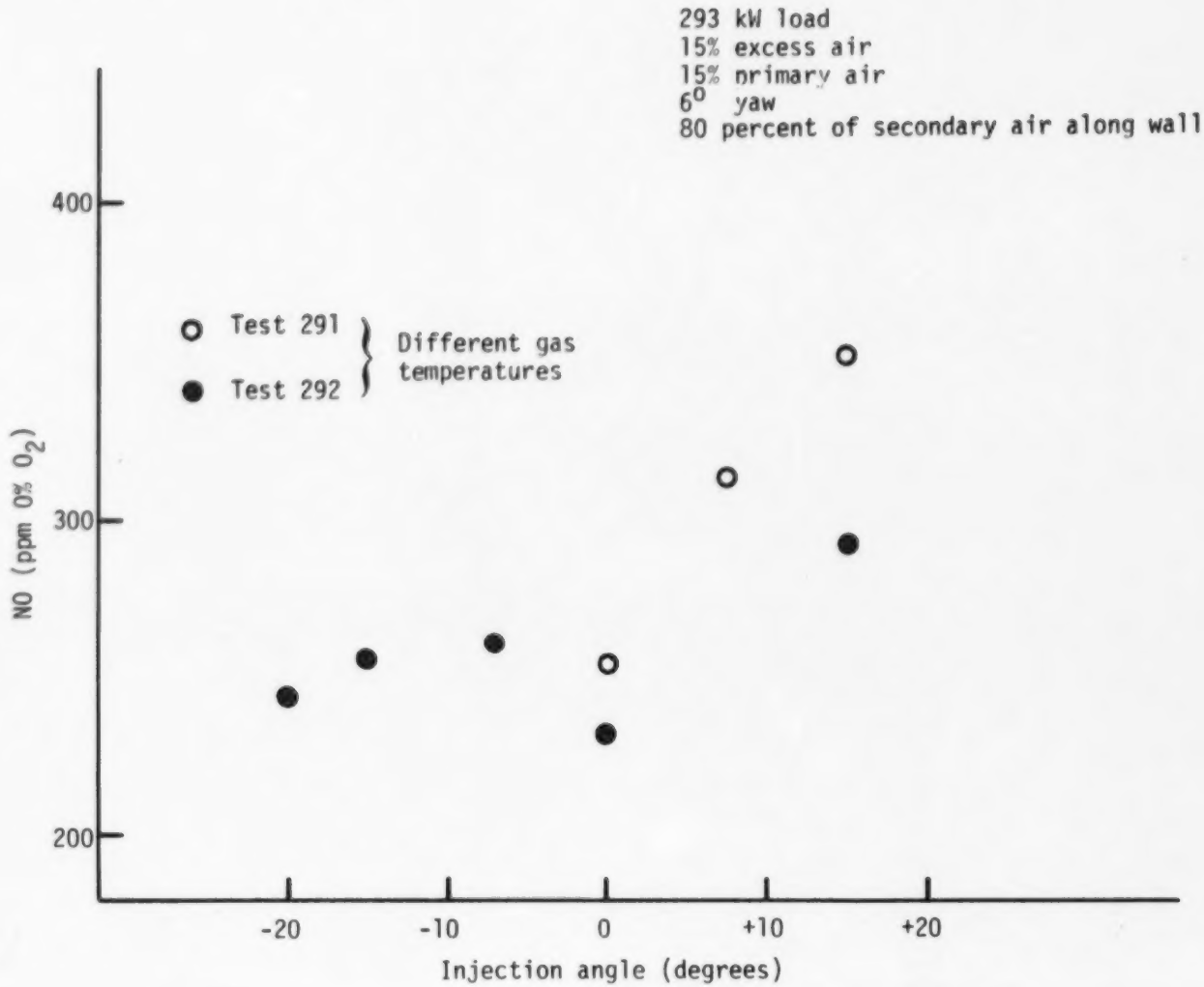


Figure 11. Comparison of NO for a variety of primary configurations with percent secondary air-on-wall,



A-23949

Figure 12. Effect of wall jet inclination angle.

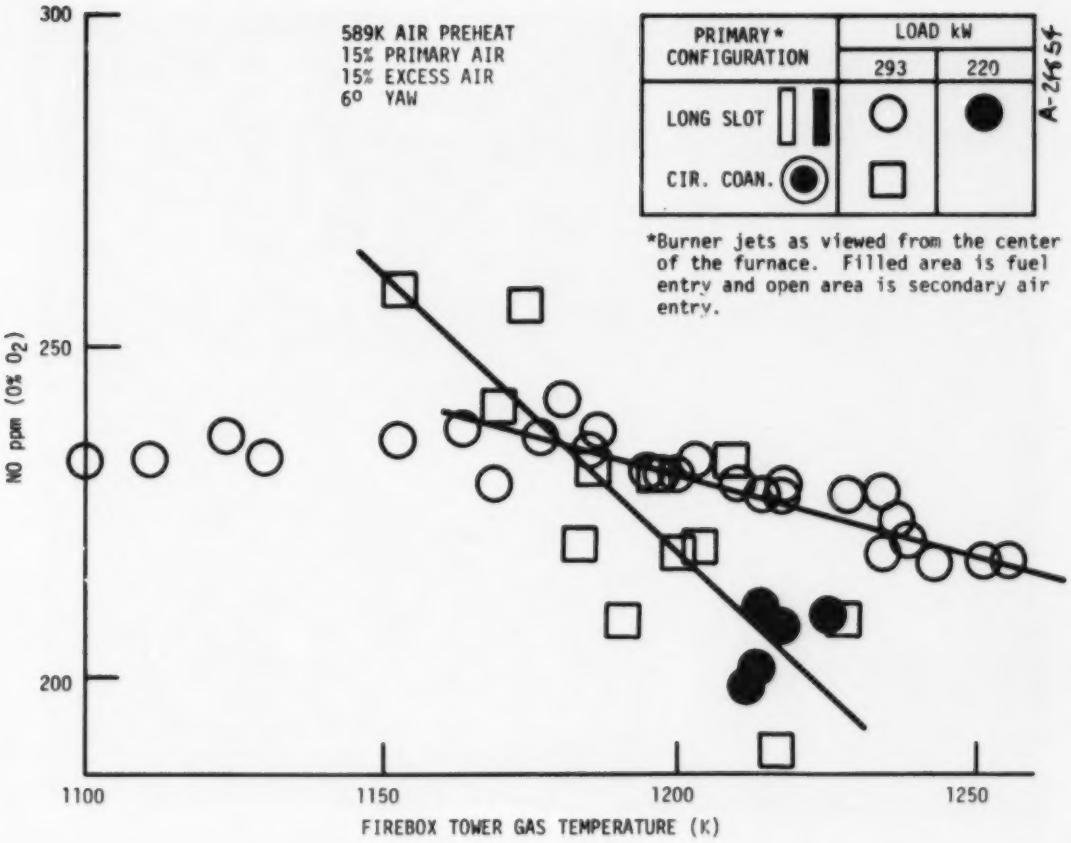


Figure 13. NO versus gas stream temperature for air-on-wall low NO_x system.

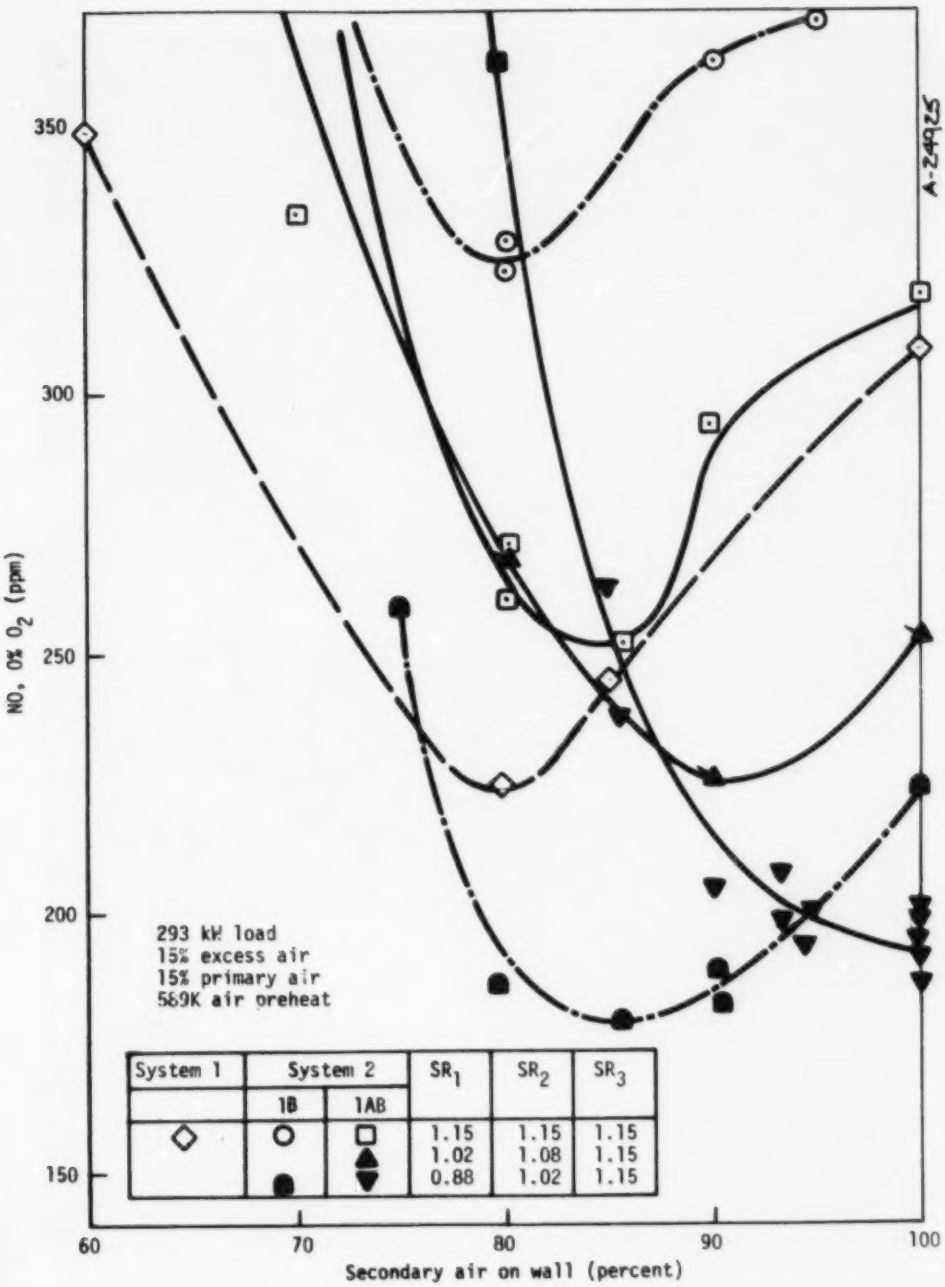


Figure 14. NO variation with percent air-on-wall for vertical wall air configurations.

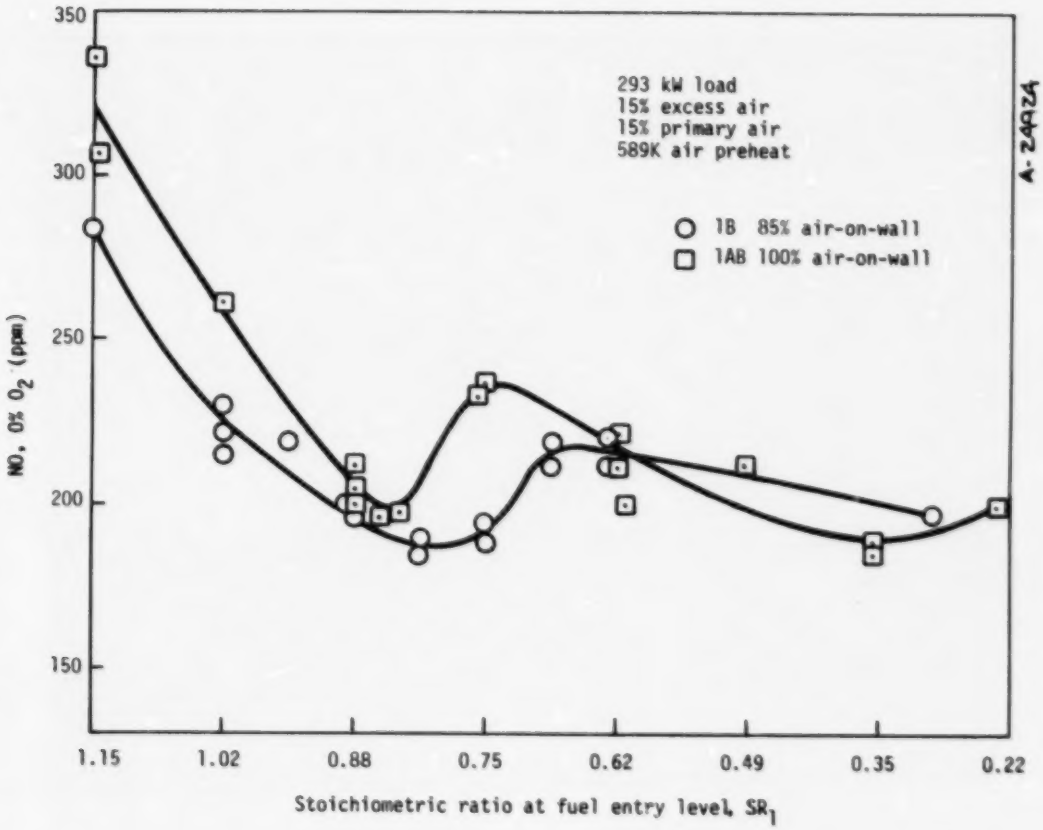


Figure 15. NO variation with wall air flow above fuel entry elevation.

TABLE I. ANALYTICAL POLLUTANT MEASUREMENT EQUIPMENT

NO/NO_x	Air Modeling Model 32C chemiluminescent analyzer
O_2	Intertech Model Magnos 5T paramagnetic O_2 analyzer
CO	Anarad Model AR500R NDIR analyzer
CO_2/CO	Anarad Model AR600R NDIR analyzer
UHC	Intertech Model FID0008 FID H/C analyzer
SO_2	TECO Series 40 Pulsed Fluorescent analyzer

TABLE II. UTAH COAL ANALYSIS

Ultimate Analysis	Dry basis (% wt)
Carbon	69.91
Hydrogen	5.15
Nitrogen	1.5
Sulfur	0.98
Oxygen (diff)	12.46
Ash	10.0
Proximate Analysis	**As received (% wt)**
Moisture	5.6
Ash	9.4
Volatile	40.6
Fixed carbon	44.4
Heating value (cal/gm) (dry basis)	6,966
Sieve analysis	77.3% wt percent through 200 mesh

THE DEVELOPMENT OF DISTRIBUTED MIXING PULVERIZED COAL BURNERS

By:

D. P. Rees, J. Lee, A. R. Brienza and M. P. Heap
Energy and Environmental Research Corporation
Santa Ana, California 92705

ABSTRACT

This paper summarizes work sponsored by the EPA to establish generalized design criteria for low emission pulverized coal burners. Data for single and multiple configurations in research furnaces at 50 and 100 x 10^6 Btu/hr are presented with the current design of distributed mixing burners. NO_x emissions down to 100 ppm (0% O_2, dry) have been obtained for bituminous coals under acceptable burnout conditions by sub-stoichiometric burner staging. These data show that the optimum burner zone stoichiometry is approximately 70 percent of theoretical air for all burners tested to date.

Section 1

INTRODUCTION

Increased utilization of coal is a major factor in the U.S. efforts to reduce imports of petroleum-based fuels. Although in the future gasification and liquifaction will provide alternate coal-derived fuels, direct coal combustion offers the only opportunity to make an immediate impact on fuel usage patterns. This paper addresses one problem associated with direct coal combustion - the production of air pollutants in general and nitrogen oxides in particular. The Federal New Source Performance Standards for boilers have recently been revised, and for nitrogen oxides (NO_x) these are dependent upon fuel type (1, 2):

- Anthracite, bituminous and lignite - 0.6 lb NO_x/Million Btu;
- Sub-bituminous - 0.5 lb NO_x/million Btu;
- Coal-derived fuels - 0.5 lb NO_x/million Btu.

These limits are achievable by current commercial practice, however their adoption will not prevent a significant increase in emissions of nitrogen oxides if the amount of coal burned by stationary sources increases. Consequently, there is considerable incentive to provide technology to reduce NO_x emissions well below those specified by the New Source Performance Standards.

Modification of the combustion process to minimize thermal and fuel NO is the most cost-effective method of NO_x control and is normally achieved by staging the heat release process in such a way as to provide an initial fuel-rich zone before all the fuel and air is mixed to allow burnout. Staged heat release can be accomplished by physical staging i.e., dividing the combustion air into two streams and injecting one of these streams into the combustion chamber some distance away from the burner supplying the fuel and part of the combustion air. An alternate method of heat release staging involves use of the burner to provide an initial fuel-rich zone. The EPA Distributed Mixing Burner (DMB) is one example

of the latter NO_x control technique. The DMB uses combined fuel injection and air delivery characteristics to provide a flame envelope which can be accomodated by existing boiler designs.

The major objective of EPA contract No.68-02-2667 is to provide information which will aid the field demonstrations of the DMB and also allow the design to be generalized to various firing configurations and the complete range of U.S. coals. This paper concentrates upon pilot scale studies concerned with burner development.

Section 2
FACILITIES

The pilot scale test facilities used in these studies have been described in detail elsewhere (3) and consist of two combustors:

- Small Watertube Simulator (SWS) with a firing range of 8-12 x 10^6 Btu/hr.
- Large Watertube Simulator (LWS) with a firing range of 50-125 x 10^6 Btu/hr.

Table 1 summarizes the dimensions and operating data for both combustors which are kept cool during the experiments by spraying water on the outside surfaces. Sample ports are located at the exit of both furances for collection of gaseous and particulate samples. Continuous monitoring instruments are used during the experiments for O_2, CO, CO_2 and NO effluent stack measurements. Both furnaces are equipped with pulverizers that produce size distributions similar to field systems. All input parameters (air temperature, flow rates, coal feed rate, etc.) are monitored during the experiments.

Table 2 lists the properties of the test fuels. The baseline fuel is a high volatile, Utah bituminous coal and to date two different shipments of this coal have been test fired (Utah I and II). Other fuels tested are listed in Table 2.

A sketch of the basic distributed mixing burner used in these studies is shown in Figure 1. It consists of a central coal pipe surrounded by annular channels for combustion air. The coal injector has a radial mixing device near the exit plane and the secondary channel includes variable annular swirl vanes. For burners consisting of two secondary channels, the amount of swirl in each channel could be controlled independently. The fuel and air flow at the burner throat is overall reducing and tertiary air to provide burnout is supplied through outboard air ports located as shown in Figure 1. The optimized dimensions and settings for the DMB are listed in Table 3 for different scales.

Section 3

SINGLE BURNER EXPERIMENTS

The effective stoichiometry immediately downstream of the burner throat is one of the most important parameters associated with low NO_x burner design. Data are shown in Figure 2 for a 50 x 10^6 Btu/hr burner in the LWS. NO_x emissions decrease steeply as the stoichiometry of the burner zone is decreased over the range shown. CO concentrations remain unchanged until the burner zone stoichiometry reaches about 60-70 percent of the theoretical air required for stoichiometric combustion (SR_B). At this point CO levels rise abruptly and overall burnout decreases. This limit is associated with a failure to mix the reactants adequately before their temperature has been reduced below some critical level.

Figure 3 shows the effect of excess air on NO emissions at fixed SR_B for two different burners in the LWS. (For these experiments, the level of excess air was varied by changing the air flow through the tertiary ducts). It is apparent from these data that NO concentrations are relatively insensitive to the overall excess air level. Provided that the conditions of the burner zone are chosen to minimize NO emissions, other parameters relating to the outboard air (i.e., velocity, position of tertiary ducts, amount of air, etc.) have a much more significant impact on CO levels and overall burnout than the NO_x emissions. This observation is consistent with data obtained using a scaled-down version of this burner in a multiple burner configuration (see Figure 4).

Other work on Distributed Mixing Burners (DMBs) to optimize the various operating parameters has been reported elsewhere (3, 4). The parameters include:

- The amount of swirl of primary and secondary streams;
- The spatial location of outboard air ducts;
- The location of the coal injector;
- The effect of coal type fuel.

As a result of these experiments, the design criteria for additional experimental and prototype burners have been established. These are listed in Table 4. These criteria were incorporated into burners to be tested in a multiple burner configuration in the LWS. These data will be described in the next section.

Section 4
MULTIPLE BURNER EXPERIMENTS

One important aspect of burner performance is the effect of burner interactions which occur in a multiple burner array. These interactions involve:

- Shielding of flames in the center of the array from the cold walls by other flames;
- Variations in the mass and temperature of the gases entrained by the flame jet;
- Variations in mixing patterns caused by the confinement of one flame by another.

In addition, only the smallest industrial boilers are fired by four burners or less. Consequently, multiple burner experiments were conducted in the LWS to study the performance of the distributed mixing burner in a multiple burner array. A single-secondary DMB with a nominal heat input of 12.5×10^6 Btu/hr was chosen for these experiments and the design criteria used were those listed in Table 4. Four burners were installed in a 2 x 2 array on a single wall of the LWS with a total heat input of 50×10^6 Btu/hr. Tertiary ports were placed so as to service each burner in a manner similar to the single burner operation. A schematic of the configuration is illustrated in Figure 4. The fuel used for most of the tests was the baseline Utah bituminous coal (Utah 1).

The overall characteristics of the heat release pattern in the 2 x 2 burner array were different from those observed when testing single burners in the LWS. The individual flames ignited within the refractory divergent and extended into the furnace as discrete flames for 2-3 feet. At the intersection of the individual flames and the tertiary air jets, the four flames joined to form a single large diffuse flame that extended into the furnace 10-12 feet. If a slight perturbation affected one of the burners, this was not reflected in the larger flame pattern. A large perturbation, however, such as a flameout in one of the

burners, would significantly alter the flame shape and burnout characteristics (CO levels and opacity of effluent gases). It was possible to test the multiple burners over a larger operating map than was possible for single burners probably because interactive effects improve burner stability.

NO and CO emissions are shown in Figure 5 over the range of excess air levels studied. NO levels lower than 125 ppm (0% O_2, dry)0.14 lbs $NO_2/10^6$ Btu were obtained before the CO levels began to be affected. In addition to the decrease in O_2 availability in the burner throat, changing the SR_B also changes the velocity in the secondary and tertiary air channels and thus might alter the overall mixing pattern. These NO levels are similar to those obtained with single burners (see Figure 3) at the same heat input. Burnout characteristics were generally better with the multiple burner configuration than with single burners.

The variation of NO and CO with load is shown in Figure 6. It was not possible to turn the burners down lower than 50 x 10^6 Btu/hr due to the capacity of the coal mill. Therefore, the burners were overfired up to 147 percent of the nominal design value (50 x 10^6 Btu/hr). The increased heat release resulted in higher NO concentrations and slightly lower CO levels. The stability and other operating characteristics were not noticeably affected. Single data points at loads of 80-90 x 10^6 Btu/hr were tested and it was possible to maintain low NO_x levels (<0.2 lb $NO_2/10^6$ Btu) by staging the burners to low SR_B (0.5-0.6). Burnout and CO characteristics were the same as, or better than, those obtained operating at the 50 x 10^6 Btu/hr heat input design point. Thus, the DMB design can compensate for conditions which would result in higher NO emissions by staging the burner to lower SR_B values.

Effect of Tertiary Parameters - Two parameters associated with the injection of tertiary air through the outboard air injectors were investigated: air velocity and removal of some tertiary ports from operation. The effect of outboard air velocity is shown in Figure 7. The nominal velocity is approximately 75 feet per second and the high velocity condition (twice normal), was achieved by reducing the flow area at the duct exit. The NO_x emissions were essentially

the same at both conditions and CO concentrations were also very similar. However, overall flame stability was reduced by increasing the outboard velocity. Small perturbations in the input conditions (air flow rates to the burner, coal feed rate, etc.) usually resulted in pulsed flickering of the flame, increased CO emission and on occasions, flameouts.

It was also possible to direct the flow of air to selected rows and/or columns of tertiary air system in the burner array (see Figure 4). This usually resulted in decreased flame stability and increased CO emissions. These changes did not have a significant impact on NO_x emissions. A summary of these data is tabulated in Table 5. The performance of the multiple burner system was most effected when the middle row or column was removed from operation. The results obtained with four burners are consistent with data obtained in the single burner experiments where NO_x emissions were more sensitive to burner zone parameters than to outboard air variables.

Fuel Effects - Three different bituminous coals were tested in the multiple burner configuration. The fuels are listed in Table 2 and the results for the fuels tested are shown in Figure 8. There were no observable differences in the general burner performance with each fuel. The NO_x emissions were nearly identical over the range of conditions tested. This is in agreement with other work in the SWS with these fuels. More work is required on fuels exhibiting a wider range of fuel properties (nitrogen, ash, heat content, water content, etc.) to formulate specific conclusions as design criteria relating to different fuels.

Section 5

SUMMARY

The pilot-scale testing of low NO_x burners has lead to formulation of specific design criteria for prototype distributed mixing burners. It is evident from these tests that burner and operational parameters affecting the burner zone can have a significant impact upon NO_x emissions. The most predominant variable identified thus far is the stoichiometry of the burner zone. Approximately 60-70 percent of the theoretical stoichiometric air for a given fuel is the optimum operating point. This same trend was observed for both single and multiple burner configurations in the LWS research furnace. It is also evident from the tests that factors affecting the outboard air have little impact on NO_x emissions over the range studied. These parameters do, however, have an impact upon fuel burnout, flame stability, and the stable range of burner operation. Results from single and multiple burner configurations are very similar. For the bituminous coals studied, the NO_x emissions appear to be relatively independent of fuel properties. This was demonstrated in both single and multiple burner configurations.

Section 6

REFERENCES

1. Federal Register, Vol 44, page 33580 (June 11, 1979).

2. Tabler, S.K., "Federal Standards of Performance for New Stationary Sources of Air Pollution", J. A. Pollut. Control Assn, 29(8).803 (1979).

3. Brienza, A. R., et al., "Development of Criteria for Extension of Applicability of Low Emission, High Efficiency Coal Burners", Second Annual Report, EPA Contract No.68-02-2667, G. B. Martin, Contract Officer, Research Triangle Park, N.C. (July 1980).

4. Folsom, B. A., L. P. Nelson, J. Vatsky and E. Campobenedetto, "Distributed Mixing Burner (DMB) Engineering Design for Application to Industrial and Utility Boilers", Special Report, EPA Contracts 68-02-3127 and 68-02-3130, G. B. Martin, Contract Officer, Research Triangle Park, N.C. (1980).

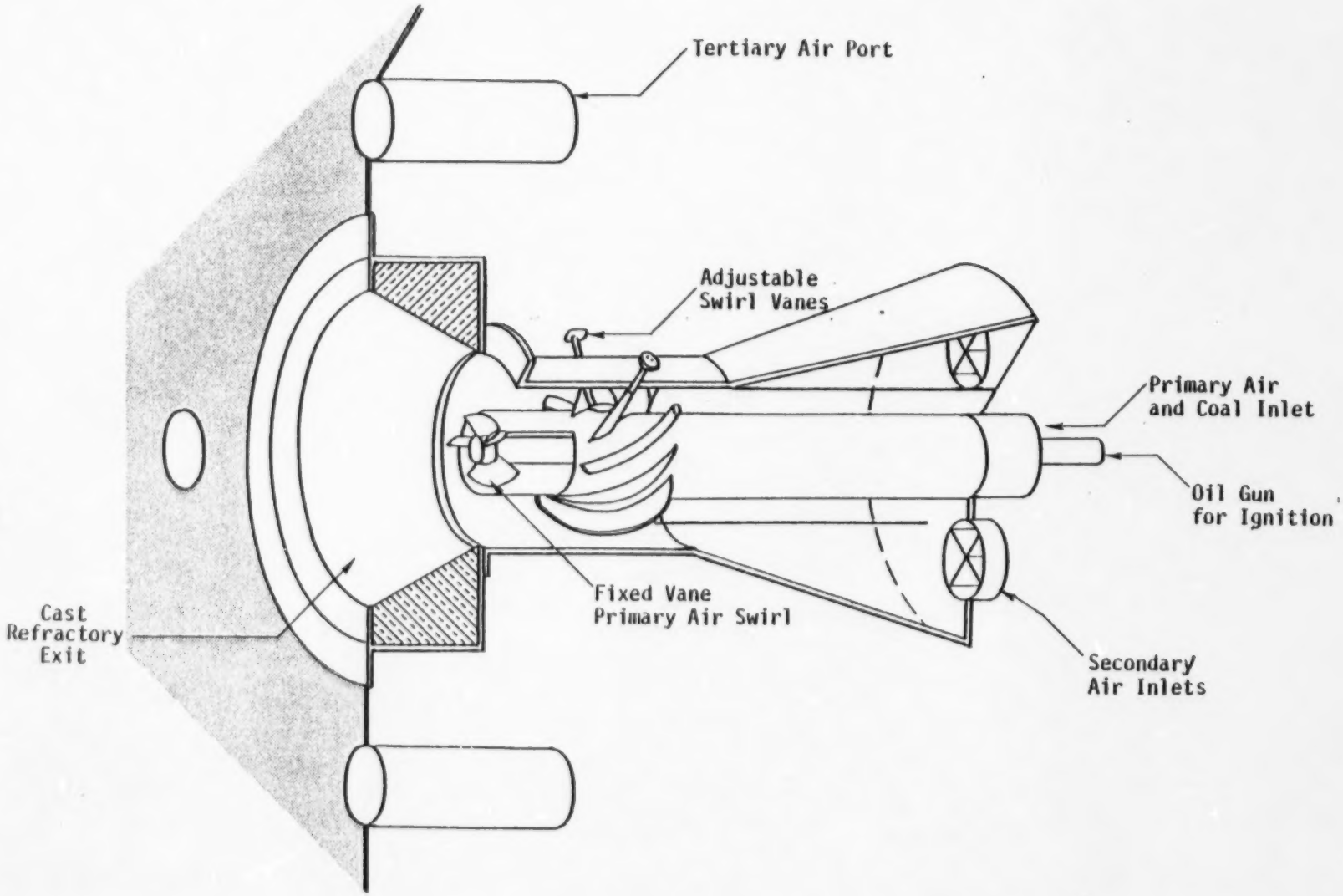


Figure 1. Single Secondary Burner (SSB) Used in Pilot-Scale Experiments.

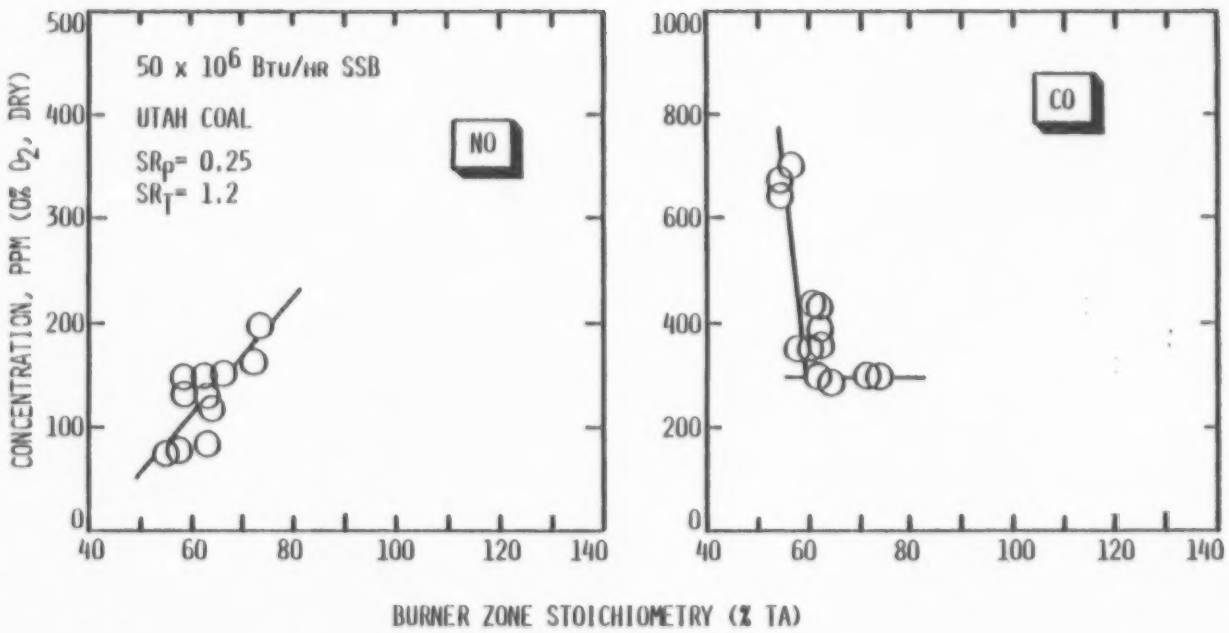


Figure 2. NO/CO Emissions from A Single-Secondary Burner in the LWS.

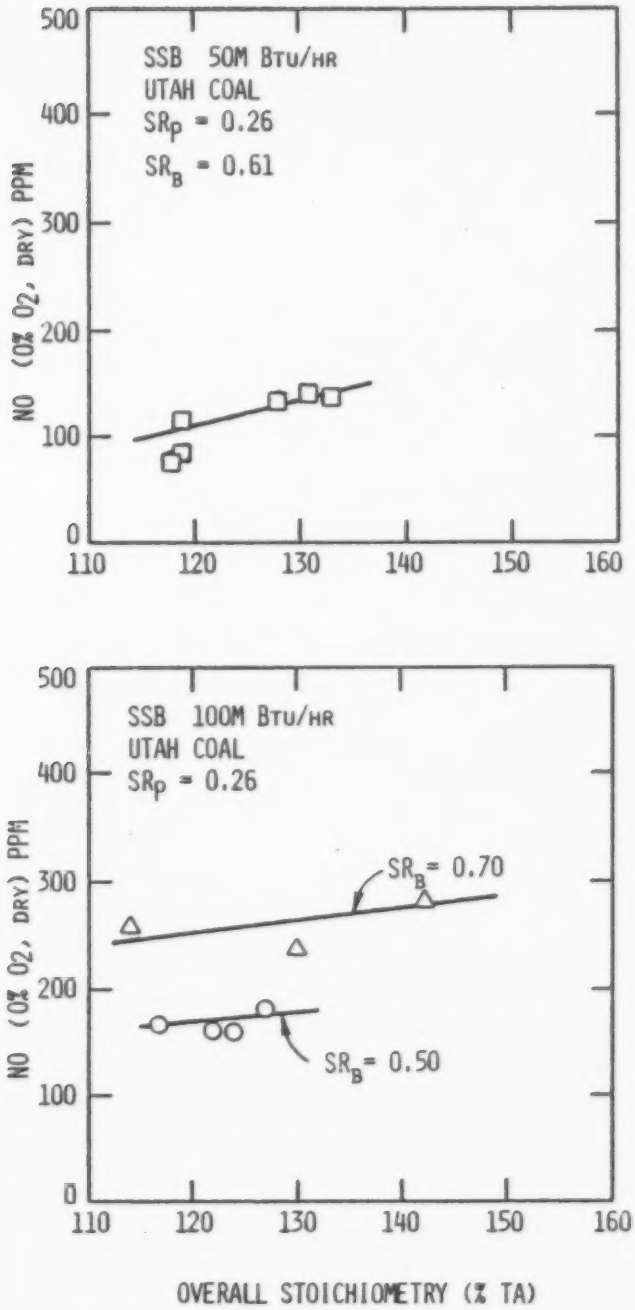


Figure 3. NO_x Emissions for Single Burners in the LWS.

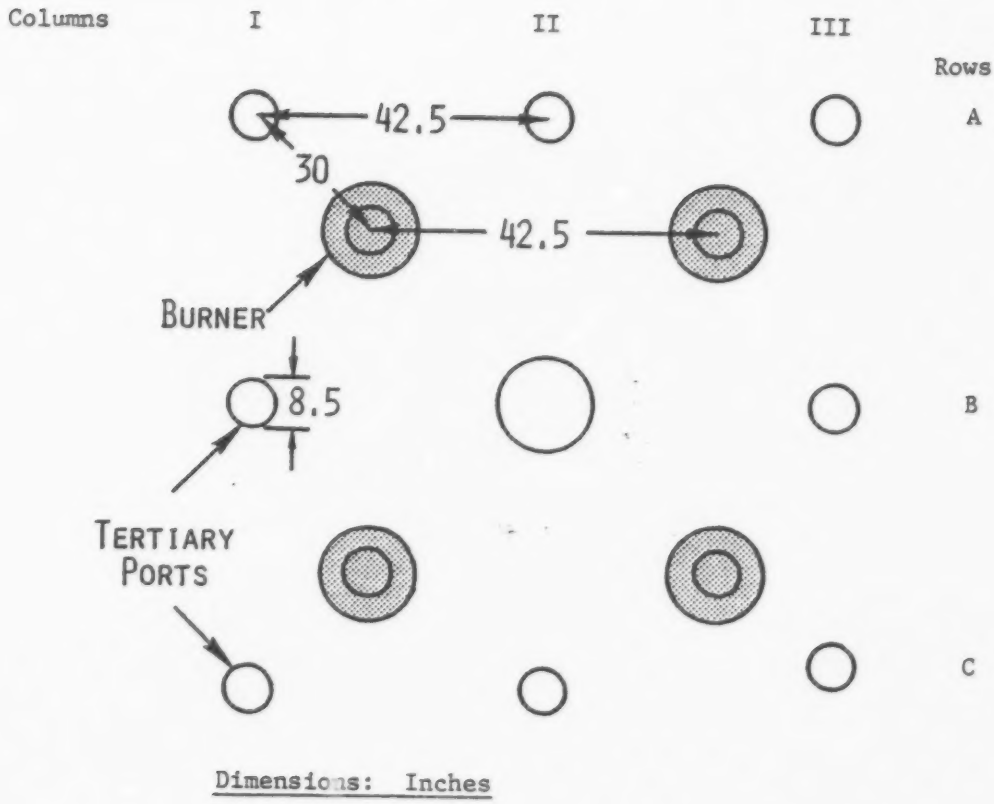


Figure 4. Schematic of Four Burner Array in the LWS.

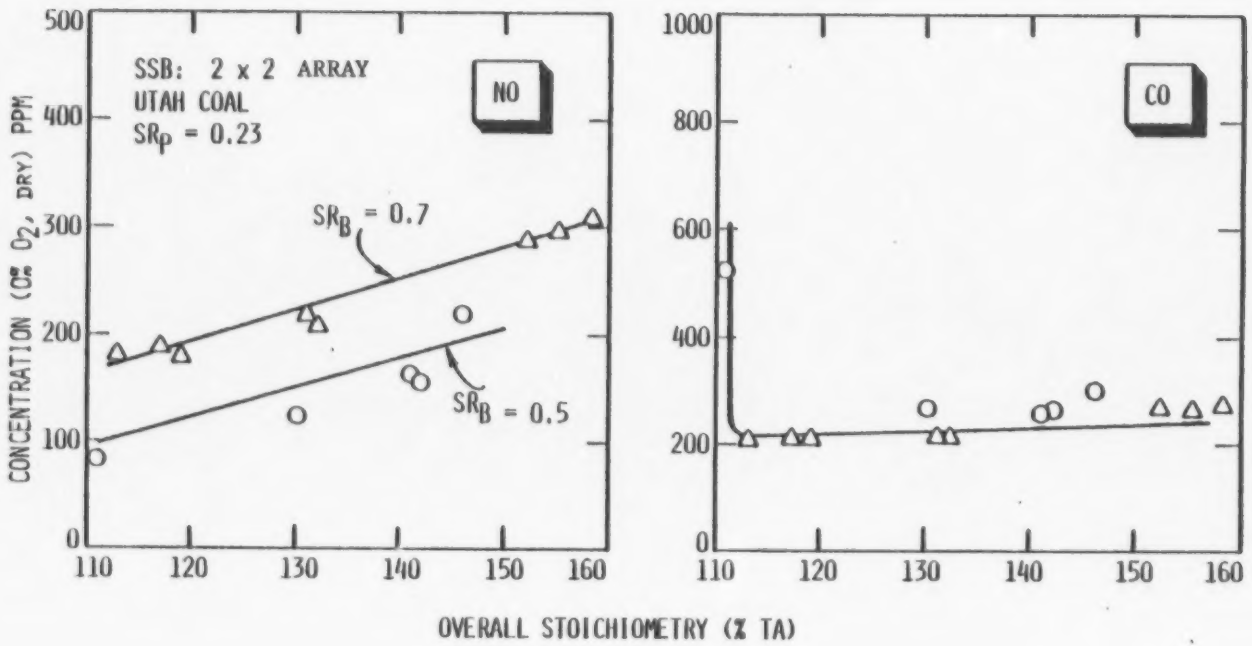


Figure 5. Emissions Profile of Multiple Burner Array in LWS.

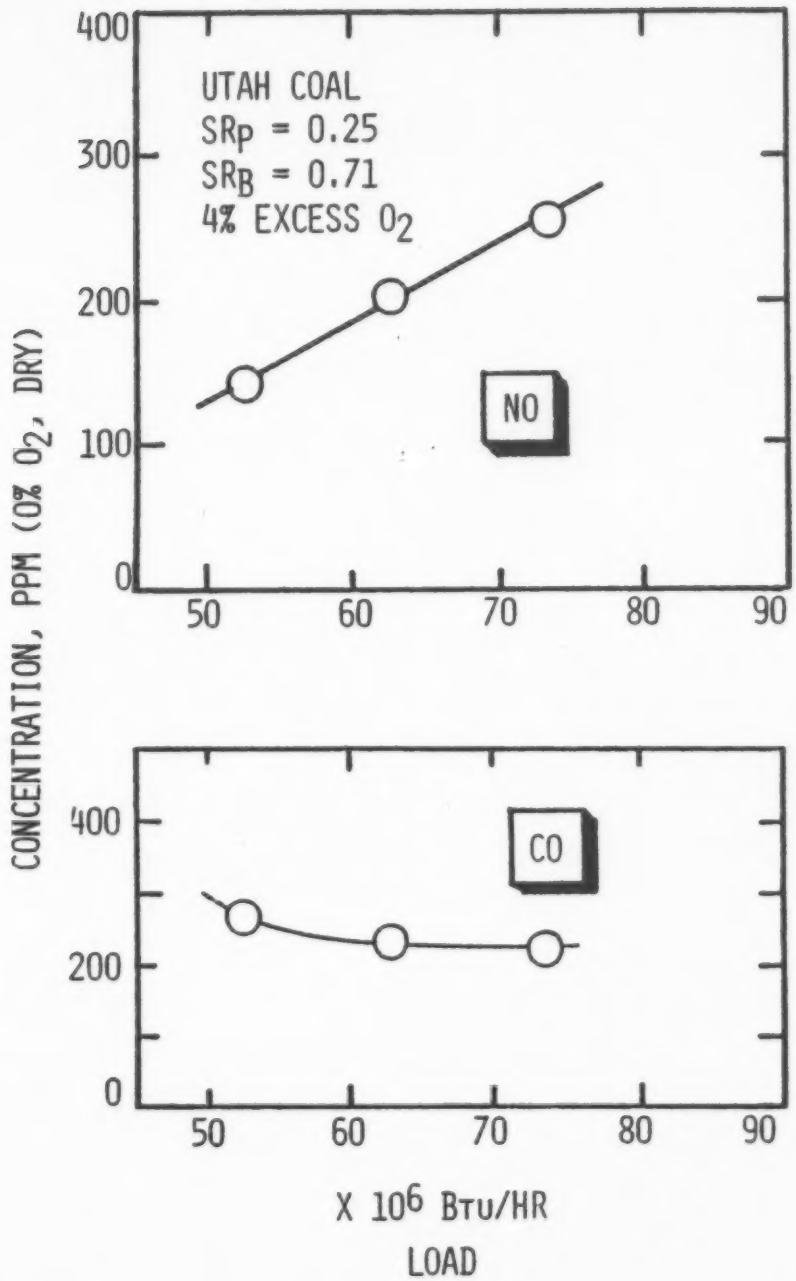


Figure 6. Emissions at Various Loads in Multiple Burner Array in LWS.

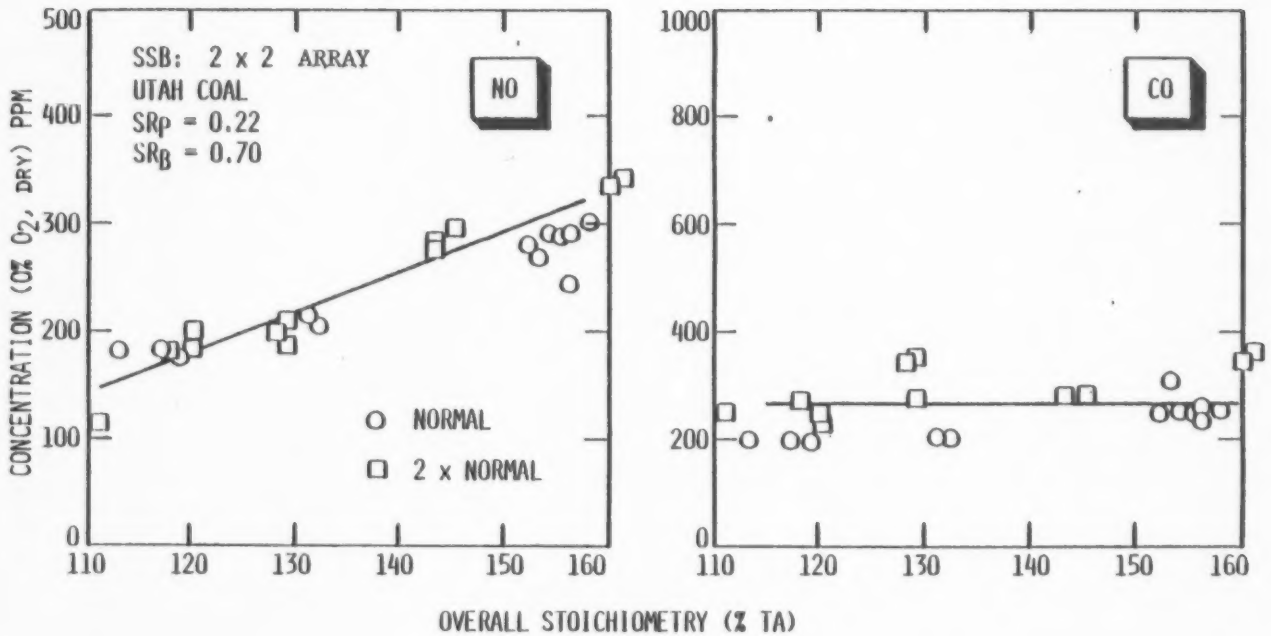


Figure 7. Effect of Outboard Air Velocity upon NO/CO Emissions from Multiple Burner Tests in LWS.

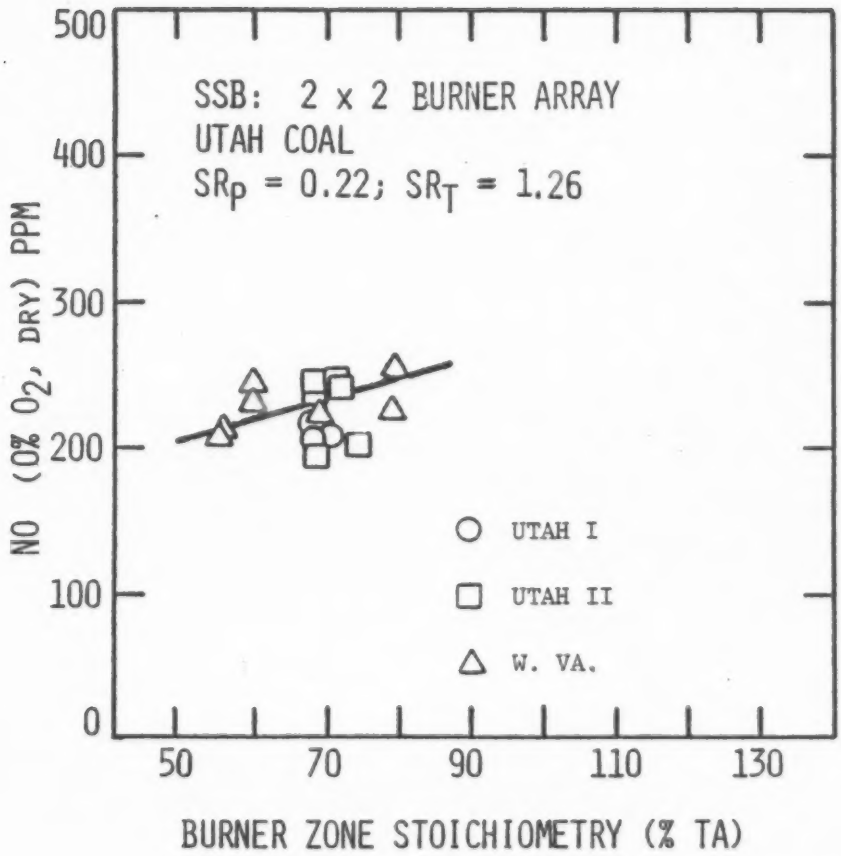


Figure 8. NO_x Emissions from Bituminous Coals in Multiple Burner Tests in the LWS.

Table I. Dimensions of Research Furnaces

	Small Watertubes Simulator (SWS)	Large Watertube Simulator (LWS)
Designed Firing Rate (Btu/hr)	12×10^6	50 to 125×10^6
Geometry	Horizontal Trapezoidal Tunnel	Vertical Rectangular with Tapered Bottom
Dimensions	5'6" H x 4'0" W x 10'0" L	59' H x 16' W x 28' D
Firing Depth (ft)	10	18
Surface Area (ft^2)	225	5050
Furnace Volume (ft^3)	207	20950
Firing Arrangement	Wall	Wall/Corner
Burner Arrangement	Single	Single/Multiple
Wall Cooling	Water-wall	Water-wall
Air Preheat (secondary)	70-500°F	70-700°F
Pulverizer (both on-line)	Hammer Mill	Bowl (C-E Raymond)
Primary Air	Unvitiated, Ambient Temperature	Vitiated, 150-170°F

Table II. Analysis of Fuels Used in Pilot Experiments

PROXIMATE, % AS RECEIVED	UTAH I	UTAH II	W. KENTUCKY	W. VIRGINIA
Moisture	6.39	7.41	5.46	1.29
Volatile Matter	38.89	38.84	36.63	31.01
Ash	7.40	8.83	8.33	13.76
Fixed Carbon	47.32	44.92	49.58	53.94
Heating Value (Btu/lb)	12,340	11,877	12,392	12,500
ULTIMATE, (% DRY)				
Carbon	73.17	72.24	73.42	72.37
Hydrogen	5.55	5.76	5.12	4.88
Nitrogen	1.42	1.54	1.59	1.34
Sulfur	0.68	0.76	3.46	1.77
Ash	7.91	9.54	8.82	13.76
Oxygen (by difference)	11.37	10.16	7.59	5.88

Table 3. Design Information for Single Secondary Burners

Design Variable	Burner Capacity (10^6 Btu/hr) 10	12.5	50	100
Fuel Injector				
Diameter (in.)	5	5.5	10.5	15.75
Area (in.^{2})	19.63	24	86	195
Swirl Angle (degrees)	Variable	45	45	45
Setback (in.)	0	0	0	0
Secondary Air Channel				
Outer Diameter (in.)	9.5	10.5	20	28
Annulus Thickness (in.)	4.5	2.5	4.75	6.1
Area (in.^{2})	51.25	63	228	421
Swirl Vanes (degrees)	Variable	60	60	60
Setback (in.)	0	0	0	0
Tertiary Ducts				
Distance from Burner ℄ (in.)	—	22	44	62
Spacing Around Burner (degrees)	22.5	90	90	90
Number of Ports	16	4	4	4
Injection Angle (degrees)	0	0	0	0
Axial Position (in.)	0	0	0	0
Diameter (in.)	4.5	6	12	16
Total Area (in.^{2})	254.5	113	452	804
Throat and Exit				
Throat Diameter (in.)	—	10.5	20	28
Throat Area (in.^{2})	—	87	314	616
Half Angle of Exit (degrees)	—	25	25	25
Length of Exit (in.)	—	9 (18.5)*	18.5	27

*Alternate exit length to match 50 x 10^6 Btu/hr burner residence time

Table 4. Prototype Distributed Mixing Burner Design Parameters

Parameter	Nominal Design Point	Testing Range
Fuel System		
Primary Temperature (°F)	S. D.	130-180
Primary Stoichiometry (% T.A.)	S. D.	17-30
Primary Velocity (ft/sec)	75	50-90
Primary Swirl	45° Vanes	Variable
Air System		
Secondary		
Temperature (°F)	S. D.	400-650
Burner Zone Stoichiometry (% T.A.)	50-70	40-120
Inner Swirl	Variable	Variable
Outer Swirl	Variable	Variable
Axial Velocity (ft/sec)	60	50-90
Inner/Total Area	0.33	Variable
Inner/Total Flow Rate	0.33	Variable
Tertiary		
Temperature (°F)	S. D.	400-650
Swirl	None	—
Axial Velocity (ft/sec)	50	40-60
Angle (degrees)	0	—
Number	4	—
Location (radius/throat diameter)	2.2	
Divergence (degrees)	0	—
Exit		
Half Angle (degrees)	25	Variable
Length/Diameter	1.0	
Setback - Inner Secondary (inches)	0	Variable
Setback - Outer Secondary (inches)	0	Variable
Operational Variables		
Capacity (10^6 Btu/hr)	S. D.	—
Turndown (% capacity)	S. D.	≈50
Overall Stoichiometry (% T.A.)	S. D.	100-150

Table 5. Summary of Effects of Tertiary Air Upon Multiple Burner Operation

CONDITION	ROW OR COLUMN* OUT OF SERVICE	RESULTS + COMPARED TO BASELINE OPERATION	
		NO	CO
I	Col. I or III	18% Low	42% High
II	Row C	25% Low	68% High
III	Row B	18% Low	32% High
IV	Column II	No Change	45% High
V	Row B and Column II	No Change	45% High
VI**	All in Service; Velocity 2 x Normal Operation	No Change	No Change

* Refer to Figure 4 for designation.

\+ Burner zone and overall stoichiometry were kept constant when rows or columns were taken out of service.

** Stable range of operation not as great as normal baseline.

THE DEVELOPMENT OF A LOW NO_x DISTRIBUTED MIXING BURNER FOR PULVERIZED COAL BOILERS

By:

B. A. Folsom and L. P. Nelson
Energy and Environmental Research Corporation
8001 Irvine Boulevard
Irvine, California 92705

and

J. Vatsky
Foster Wheeler Energy Corporation
110 S. Orange Avenue
Livingston, New Jersey 07039

ABSTRACT

This paper describes the development of a low NO_x pulverized coal burner for demonstration in two small pulverized coal-fired boilers by 1982. The "Distributed Mixing Burner" concept provides for controlled mixing of the coal with the combustion air to minimize NO_x emissions while maintaining an overall oxidizing environment in the furnace to minimize slagging and corrosion. The design of a prototype field operable burner is discussed, and test data in a research facility suggesting that NO_x emissions less than 84 ng/J (0.2 lb/10^6 Btu) might be attainable in the field are presented.

ACKNOWLEDGMENTS

This paper is based upon work conducted under Contract Nos. 68-02-1488, 68-02-2667 and 68-02-3127 with the U. S. Environmental Protection Agency. The authors wish to express their appreciation to Mr. G. B. Martin of the U. S. Environmental Protection Agency for his considerable help and advice.

SECTION 1

INTRODUCTION

The projected increase in pulverized coal use for industrial and utility steam generation will result in significant increases in pollutant emissions. One recent report predicts that NO_x emissions will increase 80 percent by the year 2000, even if current control technology is fully employed (1). Maintaining or improving the current air quality will clearly require the development and application of advanced NO_x control techniques. Combustion modification through the installation of low NO_x burners is one of the most promising techniques for reducing emissions without greatly increasing overall costs or reducing efficiency.

For the last several years Energy and Environmental Research Corporation has been working with the EPA to develop a low NO_x pulverized coal burner. This "Distributed Mixing Burner", DMB, provides for controlled mixing of the coal with combustion air to minimize NO_x emissions while maintaining an overall oxidizing environment in the furnace so as to minimize the detrimental effects of furnace corrosion. DMBs have been tested at firing rates up to 29 thermal MW (100×10^6 Btu/hr) in single and four-burner arrays in two research furnaces. The tests covered wide ranges of burner adjustments and operating conditions. Under optimum experimental conditions, NO_x levels less than 65 ng/J (0.15 lb/10^6 Btu) were obtained (2). The minimum NO_x levels obtainable in field operating boilers will, of course, vary with boiler design and operating conditions and may be higher than these experimental results.

Application of the DMB concept to new pulverized coal-fired boilers requires an evaluation of long-term performance in field boilers. This

evaluation is being conducted on small pulverized coal-fired boilers (less than 455 x 10^3 kg: 1.0 X 10^6 lb of steam per hour) under EPA Contract 68-02-3127 and on larger utility boilers under EPA Contract 68-02-3130 (3). The small boiler demonstration, which is the subject of this paper, has been scheduled first so that the larger utility boiler demonstration can benefit from the test results. However, the actual burner components being utilized in each program are representative of those which are used commercially by the respective boiler manufacturers. Consequently, the utility program (68-02-3130) will benefit from the small boiler program (68-02-3127) only in that the concept will be first demonstrated in the field in the small boiler program. The burner components provided to the small boiler program will not be utilized in the utility program.

The small boiler demonstration involves two Foster Wheeler front wall-fired units which are representative of industrial size boilers. The first unit has a capacity of 98 x 10^3 kg/hr (215 x 10^3 lb/hr) and has four burners in a 2 x 2 array. The second unit being considered has a capacity of 175 x 10^3 kg/hr (385 x 10^3 lb/hr) and has six burners in a two-high by three-wide array. The DMBs to be installed in these units will be designed by incorporating DMB flow parameters into a commercial burner design and adding the requisite number of tertiary air ports. Prototype burners will be fabricated by Foster Wheeler using commercial burner components and construction methods. The design parameters will then be optimized by testing in the research furnace. The final configurations will be installed in the field boilers and tested for 18 months duration. During this long-term evaluation all aspects of the burner/boiler performance will be assessed, including: NO_x emissions, other environmental impact, burner and boiler efficiency, durability, operability, safety, boiler performance and integrity and heat transfer surface duties.

This paper discusses the status of the DMB under development for the initial demonstration. The prototype burner has been designed and fabricated. The test data leading to the DMB design criteria and the prototype burner design are discussed in the following section. The prototype burner and a burner similar to the burners currently installed in the initial demonstration boiler have been tested in the research furnace. The results of these

tests and an estimate of potential DMB performance in the initial demonstration boiler are discussed in Section 3.

SECTION 2

PROTOTYPE DMB DESIGN

The prototype DMB for the initial field demonstration has been designed to meet the following requirements:

- DMB design criteria
- Compatibility with host burner/boiler specifications
- Commercial burner construction methods and operational characteristics

DMB DESIGN CRITERIA

The DMB concept involves staging the combustion process to minimize NO_x emissions while maintaining an overall oxidizing atmosphere in the furnace so as to have minimal impact on furnace slagging and corrosion. NO_x production from fuel nitrogen compounds is minimized by driving a majority of the compounds into the gas phase under fuel-rich conditions and providing a stoichiometry/temperature history which maximizes the decay of the evolved nitrogen compounds to N_2. Thermal NO_x production is also minimized by enthalpy loss from the fuel-rich zone which reduces peak temperatures.

A schematic representation illustrating how the DMB design sequentially stages the fuel/air mixing is shown in Figure 1. The combustion process occurs in three zones. In the first zone pulverized coal transported by the primary air combines with the inner secondary air to form a very fuel-rich (30 to 50 percent theoretical air) recirculation zone which provides flame stability. The coal devolatilizes and fuel nitrogen compounds are released to the gas phase. Outer secondary air is added in the second "burner zone" where the stoichiometry increases up to about 70 percent theoretical air.

This is the optimum range for reduction of bound nitrogen compounds to N_2 (2). Air to complete the combustion process is supplied through tertiary ports located outside the burner throat. This allows substantial residence time in the burner zone for decay of bound nitrogen compounds to N_2 and radiative heat transfer to reduce peak temperatures. The tertiary ports surrounding the burner throat provide an overall oxidizing atmosphere in the burner zone.

Figure 2 shows the DMB as it would be installed in the small wall-fired boiler. This DMB design uses components illustrated below:

- Four independently controlled airstream systems divide the total combustion air into:
  1. An annular coal nozzle;
  2. A central passageway containing an ignitor for start-up;
  3. Two concentric secondary airstreams to provide inner and outer secondary airflow; and
  4. Four outboard tertiary air ports.
- The annular fuel nozzle and tangential coal inlet produce a uniform annular coal distribution.
- Two adjustable air registers connected to the secondary air passages to control both the airflow rates and degree of swirl.
- Ignition and main flame scanner systems for safety.

Six DMB configurations using other components have been evaluated in two research furnaces to determine the effects of design parameters on flame shape and stability, as well as efficiency (as indicated by CO emissions) and NO_x emissions. These burners ranged in capacity from 3.6 thermal MW (12.5×10^6 Btu/hr) to 29 thermal MW (100×10^6 Btu/hr), and were tested as single burners. In addition a 2X2 array of 3.6 thermal MW (12.5×10^6 Btu/hr) burners was also tested. Each configuration was evaluated over a range of operating conditions and the ersults will be discussed in terms of the following burner systems:

- Fuel System
- Secondary Air System
- Tertiary Air System

Fuel System

The DMB fuel system includes the following geometric variables and fuel/air characteristics through the fuel nozzle:

- Primary stoichiometry
- Nozzle size and axial position
- Exit velocity
- Swirl

The effects of each of these variables (except nozzle size) on burner performance have been evaluated. Although nozzle size has not been specifically evaluated, it is considered to have only secondary effects on burner performance over the practical range.

The DMBs tested in the research furnaces utilized a circular coal nozzle located on the burner axis. In two of the burners there was no provision for primary swirl, and as a result, the rate of mixing between the primary and secondary streams was low. This produced a longer diffusion-type flame and low NO_x emissions. Long flames can be utilized in furnaces with sufficient depth and when low burner liberations are used. However, the goal of this program is to develop a burner which has a short flame, requires no reduction in burner capacity, and is more compatible with a wide range of furnace configurations including short furnace depths of 6 m (20 ft) or less. The other DMB configurations tested in the research furnaces included impellers in the nozzle to impart swirl and increase the rate of mixing between the primary and secondary airstreams. The resulting flames were considerably shorter, but had slightly higher NO_x emissions. The following discussion will include the test results from the short flame burners. Test results from the long flame burners are discussed in References 2, 3 and 4.

Figure 3 shows some typical results obtained with a 14.6 thermal MW (50×10^6 Btu/hr) single secondary DMB firing at full load and 125 percent theoretical air. Minimum NO_x levels are in the range of 100 ppm* which

*All NO and CO concentrations in this paper are corrected to 0 percent O_2, dry conditions.

corresponds to 46 ng/J (0.11 lb/10^6 Btu). CO emissions are in the range of 250-500 ppm which is considerably higher than typical burner performance in field boilers (~50 ppm). This difference is believed to be a consequence of the research furnace design, and will be discussed in a subsequent section. With the swirl vanes removed (axial flow) it was not possible to obtain acceptable flame stability. At 30° swirl angle an acceptable flame was achieved with minimum emissions, and no measurable increase in NO_x was observed when the swirl angle was increased to 45°. Further increasing the swirl angle to 60° resulted in a large increase in NO_x. Due to the limited range and scatter in the CO data, the effect of swirl angle on CO is unclear. The indicated lines represent a best judgment as to interpretation of the results. This interpretation would indicate that both the fuel/air mixing characteristics and ignition flame characteristics are changing significantly. Therefore, there should be a design trade-off between NO and CO with primary swirl, with lower swirl angles providing lower NO_x levels. However, if in the final configuration the CO levels are extremely sensitive to burner parameters, then this will limit its NO_x capabilities. Ignition stability represents the lower limit of operation, although it would not be prudent to design at that low a level. Since ignition stability plays a key role in the ability to minimize both NO and CO, the specific design parameters will depend on the site-dependent conditions. It is not yet known if the burners' NO_x capabilities will vary with these site-dependent conditions.

Secondary Air System

The DMB secondary air system includes all components which provide air through the burner throat except for the coal nozzle. Specific variables include:

- Air distribution between secondaries
- Velocity
- Swirl
- Burner zone stoichiometry

The DMBs tested in the research furnaces included designs with single, as well as dual secondary air passages. The dual secondary design is preferred because of the additional control over fuel/air mixing rates which can be

achieved by varying the flow rates and swirl in the two secondary passages. However, for simplicity, most of the DMBs were designed with a single secondary air passage.

Figure 4 shows the effects of secondary air system variables on the performance of the single secondary 14.6 thermal MW (50 x 10^6 Btu/hr) burner. The operating conditions were the same as for the data presented in Figure 3, and the primary swirl was 45°. Variations in burner zone stoichiometry are produced by varying the amount of air through the outboard tertiary air passages. For burner zone stoichiometries equal to the overall stoichiometry (125 percent theoretical air) all of the air passes through the burner throat (unstaged condition). Figure 4 shows that for unstaged conditions the DMB produces NO and CO levels of 400 and 300 ppm, respectively. As the burner zone stoichiometry is decreased (air diverted through the tertiary ports) keeping the overall stoichiometry constant at 125 percent theoretical air, NO decreases. At a burner zone stoichiometry of 60 percent theoretical air the range of NO_x is 90-180 ppm. CO remains essentially constant down to about 70 percent theoretical air where the airflow through the secondary air passages has decreased to the point where the flame stability decreases and CO emissions rise. While the flame is still stable initially, continued reduction in burner zone stoichiometry eventually leads to instability and flameout. Due to the onset of instability, operation near the knee of the CO curve is unacceptable. Consequently, actual NO levels in the field may be higher than those shown in Figure 4. For this burner, operation at 70 percent throat stoichiometry appears to be acceptable. Under this minimum condition NO_x is about 0.2 lb/10^6 Btu.

In comparing the CO and NO characteristics, note that the impact of burner zone stoichiometry on NO remained unchanged even as the CO markedly increased. This suggests that the NO formation is being controlled principally by the burner zone stoichiometry and not by the primary/secondary mixing rates. The conditions producing the increase in CO shown in Figure 4 were found to be strongly dependent on the burner settings, as well as design velocity. In fact, at full load it was possible to obtain minimum CO and NO over a wide range in excess air levels by simply varying both burner zone stoichiometry and swirl conditions. (This is not meant to imply that it is the intent of this program to vary the burner setting in the field during the

load or excess air changes). Although not shown in Figure 4, at zero swirl the flame could not be operated stably, even at high burner zone stoichiometry, and resulted in flameout. As secondary swirl was increased to 30° it was possible to achieve a stable flame over a burner zone stoichiometry range from about 70 percent theoretical air to essentially unstaged conditions (120 percent of theoretical air). Lower burner zone stoichiometries were possible as the secondary swirl angle was increased. Note that the NO characteristics were essentially unchanged with secondary swirl angle, while the burner performance (CO) was improved by increasing secondary swirl. Thus, there is a trade-off in NO and CO emissions as burner zone stoichiometry and swirl are varied. Optimum values with this burner for invarient operating conditions are: (1) secondary swirl angles of 30° to 45°, and (2) a burner zone stoichiometry of about 60 percent theoretical air.

Tertiary Air System

The DMB tertiary air system includes all components which provide air through the tertiary air passages. Specific variables include:

- Velocity
- Number of ports
- Location of ports

Variations in tertiary velocity have been found to have little effect on NO and CO emissions for tertiary port configurations of practical significance. However, the number and location of the tertiary ports have been found to affect CO but not NO emissions. Figure 5 shows some results from tests of a four-burner array of 3.6 thermal MW (12.5×10^6 Btu/hr) DMBs. The tertiary ports for adjacent burners were combined as shown to minimize the total number of tertiary ports. The tests were conducted by maintaining the secondary air flow rate (burner zone stoichiometry) constant and varying the tertiary air flow rate (overall stoichiometry) and the number of ports in service. The decrease in NO as the overall stoichiometry is reduced is typical of performance for most burners. CO emissions for all ports in service are constant, independent of overall stoichiometry, over the range tested. Although not shown in Figure 5, lower values of overall stoichiometry (less than 110 percent theoretical air) caused a sharp increase in

CO and smoke emissions. This is also typical performance for most burners.

Tests were conducted with various rows and/or columns out-of-service to define the sensitivity of NO and CO to the number and location of the tertiary ports. The results presented in Figure 5 show that within experimental accuracy the NO characteristics were completely unaffected by the variations in tertiary air velocity or tertiary port location. The general conclusion from this is that for these short flames the burner zone is essentially premixed and burns at the burner zone stoichiometry and, therefore, NO is formed in the burner flame zone before substantial interaction with the tertiary air. While NO was not affected by tertiary port location in the multiburner configuration, the variations in CO were dramatic. Note that unsymmetric changes in tertiary ports out of service were accompanied by an increase in CO. This result reveals that the tertiary port location relative to the burners has a strong impact on the overall mixing in the lower furnace, and that improper port location will result in incomplete CO burnout in the high temperature region of the furnace.

Based upon the test results presented above and other data involving variations in exit geometry, operating conditions and coal composition, nominal prototype burner design criteria have been identified and are listed in Table I. These criteria are nominal in that they are the starting point for prototype burner testing and final optimization.

HOST BURNER/BOILER SPECIFICATIONS

The boiler selected for the initial demonstration is Pearl Station which is owned and operated by Western Illinois Power Cooperative (WIPCO). Table II lists the characteristics of this unit which impact prototype burner design. The coal currently supplied to this unit is an Indiana bituminous coal with the characteristics listed in Table III.

The Pearl Station characteristics are compatible with the DMB design criteria listed in Table I with the following exceptions:

- Windbox Depth and Burner Exit Length. The windbox depth is designed for the currently installed pre-NSPS Intervane burners which have a single register and a short exit. However, it is too short to accommodate the dual registers and exit length

specified in the DMB design criteria. The maximum exit length which can be used corresponds to about 40 percent of the prototype DMB throat diameter, whereas the design criteria specify 100 percent. Burner exit geometry affects flame stability and the effects of this short exit length were evaluated in the prototype tests (Section 3).

- Burner Spacing and Tertiary Port Locations. The burner spacing is too close for the tertiary ports to be located as specified in the design criteria. In addition, windbox and furnace structural considerations limit the potential tertiary port locations. Figure 6 shows the tertiary port locations selected for the WIPCO unit. Although this configuration deviates from the design criteria, the tertiary air is well-distributed around and between the burners and the velocity matches the design criteria.

  It should be noted that installation of the tertiary air ports results in removal of a buckstay and elimination of most of the firing wall support tubes. Consequently, an under hopper support must be installed. This technique is questionable for larger utility boilers and an alternate approach would have to be developed for this equipment.

PROTOTYPE BURNER DESIGN

The prototype DMB for the initial industrial boiler demonstration has been designed by integrating the DMB design criteria and the host firing system/boiler characteristics into a design using commercial burner components. The prototype DMB has been designed to allow variation of several burner parameters during testing. The optimum configuration will then be used as the basis for field operable burners.

Figure 7 is a cross-sectional view of the prototype burner showing its design details. The following Foster Wheeler commercial burner components have been incorporated into the design:

- Annular Coal Nozzle
- Telescoping Coal Nozzle for Primary Velocity Control
- Registers for Swirl Control and Flow Shutoff

- Air Hoods for Secondary Flow Rate Control and Measurement
- Commercial Flame Scanning and Ignition System

The coal and primary air enter the annular coal nozzle through a tangential inlet to provide swirl. The coal nozzle is a tapered annulus. The exit end of the coal nozzle is formed from two concentric cones. The inner cone can be moved axially to vary the exit area, and hence, the primary velocity. The outer portion of the coal nozzle is constructed of removable sections so that the overall length of the coal nozzle may be changed to vary the nozzle setback within the burner throat. There are two concentric secondary air passages supplied from a common windbox. Each is equipped with an adjustable register for swirl control, an axially movable sleeve for flow control and perforated plate (air hood) for flow rate measurement. Pressure taps on both sides of each perforated plate allow the pressure drop to be measured and correlated with sleeve position and flow rate.

The portion of the burner inside the coal nozzle is termed the core, and is supplied with a small amount of cooling air from the windbox. A retractable ignition system, including spark ignition, a 2.9 thermal MW (10×10^6 Btu/hr) oil gun and an ignition flame scanner is located in the core on the burner centerline. The main flame scanner views the flame through the inner secondary air passage.

Tertiary (staging) air is supplied from the windbox through outboard tertiary air ports. During testing in the research facility the airflow rate through each port will be controlled and measured by the assembly shown in Figure 8. The hemispherical poppet pivots to vary the open area, and thus, control the flow rate. The pressure drop across the perforated plate air hood provides an indication of flow rate. Alternate tertiary air port control system designs will also be evaluated during the prototype burner tests.

In summary, the prototype burner has been designed with "flexible" parameters to permit the flow rates, velocities and swirl in the burner passages to be varied to optimize burner performance. The dimensions and ranges of adjustment are listed in Table IV. All of the dimensions listed match the prototype design point except the exit length and tertiary port locations as previously discussed. The effects of these deviations from the design criteria will be evaluated during prototype tests.

SECTION 3

COMMERCIAL BURNER AND PROTOTYPE DMB TEST RESULTS

The prototype DMB design which will be recommended for installation and demonstration in a field-operating steam generator must be capable of (1) stable characteristics while (2) providing low NO_x levels. Since the DMB prototype burner design was based on the results of tests in the research furnace, some assurance is required that these test results can be used to predict burner performance in the field boilers. Though indirect, the approach taken was to evaluate the operating characteristics of a commercial burner in the research furnace and compare the results with field experience. Similarity of the research furnace and field results were then taken as an indication that the operating characteristics of the DMB in the research furnace and in field operating boilers would also be similar. In addition, burner manufacturers have found that when two burners are tested in a research facility that the ratio of NO_x emissions measured in the test facility will be comparable to the ratio of NO_x emissions when the identical burners are operated in field boilers. Thus, the ratio of NO_x emissions for a commercial burner and the prototype burner tested in the research furnace should be approximately the same as the ratio of NO_x emissions from the same burners operated in the host boilers.

COMMERCIAL BURNER TESTS IN THE RESEARCH FURNACE

A Foster Wheeler Intervane burner similar to those in service at the initial demonstration site has been tested in the research combustor. In general, the burner performance was similar to that observed in field boilers. The flame was short, bright, intense and stable, but somewhat narrower and longer than those observed with multiburner arrays in the field. This suggests

that the DMB flame shape and stability characteristics observed in the research furnace will be similar in the field.

The CO and NO characteristics for the Intervane burner tested in the research furnace are shown in Figure 9. The CO characteristics are more sensitive to excess air variations than observed in the field. For example, in field units it is expected that the sharp rise in CO would occur at a lower value of excess air (110 percent T.A.) than that shown in Figure 9. In addition, the asymptotic value of CO measured in the research furnace was about 185 ppm (corrected to 0 percent O_2) which is greater by a factor of four than that observed in multiburner field units, less than 50 ppm. This suggests that the high CO levels measured in the research furnace may be a result of the furnace design and sampling point location (at the furnace exit). The LWS is currently being modified to correct the suspected causes of high residual CO emissions. The Intervane burner will be retested to determine if the resulting CO emissions match those obtainable in the field.

The variations of NO with load and overall stoichiometry are within the normally observed field ranges. However, the NO levels are 50 to 100 ppm lower than expected in a multiburner field operating boiler. Figure 9 also shows typical NO levels from four-burner bituminous coal-fired boilers similar to the initial demonstration site. Extrapolation of the research furnace results to full load (16.4 thermal MW (90 x 10^6 Btu/hr)) gives an NO level of 500 ppm while 600 ppm are typically measured at full load in field units. The NO emissions from the initial demonstration boiler are expected to be in this range. This will be verified during baseline tests of the unit.

PROTOTYPE DMB TESTS IN THE RESEARCH FURNACE

The prototype DMB has been tested in the research furnace. This initial test series was brief and primarily evaluated performance without tertiary ports (unstaged). The flame was bright and somewhat longer and wider than the Intervane burner flame. There was no indication of flame impingement on the target wall which was 4.88 m (16.0 ft) from the firing face. The DMB should, therefore, be compatible with the initial demonstration boiler where the furnace depth is 6.28 m (20.6 ft).

The NO and CO characteristics for the prototype DMB operating unstaged and the Invervane burner are shown in Figure 10. The NO emissions for the prototype DMB are comparable to those measured when previous DMB designs were tested unstaged. However, they are 50 to 100 ppm lower and more sensitive to overall stoichiometry than the Intervane burner. The lower NO level is expected because the prototype DMB has dual registers and lower throat velocity than the Intervane burner, and thus, lower fuel/air mixing rates. CO emissions at a typical operating condition of 125 percent theoretical air are also somewhat lower for the prototype DMB. However, this is probably not significant as discussed above.

It should, however, be noted that this prototype DMB's geometrical configuration has not been optimized. Since this design is based on Foster Wheeler's commercial hardware, which has been adapted to meet DMB velocity and flow criteria, further geometrical changes may be necessary to obtain optimum NO and CO performance with acceptable stability. Among the differences between this prototype and EER's previous experimental DMBs are:

Prototype DMB	Experimental DMBs
Registers for swirl control	Block-type swirl generators
Annular coal nozzle with tangential inlet	Cylindrical pipe nozzle with articulated inlet
Open coal nozzle outlet with adjustable velocity feature	Impeller/swirler at outlet fixed velocity
Medium quarl depth	Long quarl depth

It is reasonable and prudent to assume that these differences can result in NO and CO performance which are also different. The prototype results were obtained with an initial geometry which is likely to be nonoptimum. Consequently, as part of the test program, the prototype's geometrical and flow parameters will be varied to determine the configuration which provides optimum NO, CO and stability performance.

A limited test series was conducted with the prototype DMB operating staged to obtain an approximate indication of its potential for low NO emissions. These tests were preliminary; no attempt was made to optimize burner adjustments and the burner was not operated at the design point. The results

in Figure 11 show the same decrease in NO as burner zone stoichiometry decreases as that observed in tests of other DMB designs. Extrapolation to the DMB design point (overall stoichiometry 118 percent theoretical air and burner zone stoichiometry 70 percent theoretical air) results in approximately 100 ppm NO. CO emissions increased to unacceptable levels as burner zone stoichiometry decreased. This is probably due to nonoptimum burner configuration and adjustment. Optimization of burner adjustments and of burner geometry should result in the characteristic knee as in Figure 4.

ESTIMATE OF NO EMISSIONS FROM THE FIELD DEMONSTRATION

A rough estimate of the potential NO emissions from the DMB operating in a small pulverized coal-fired boiler can be made from these data. The prototype DMB and Intervane burners have been tested in the research furnace at 23.4 thermal MW (80 x 10^6 Btu/hr) firing rate and 125 percent theoretical air. Field data are also available for Intervane burners operating in small pulverized coal-fired boilers. The table below summarizes these results and presents an estimate of the NO emissions from the DMB operating in a small pulverized coal-fired boiler based on the ratio technique described above.

	Research Furnace		Field Burner	
	NO (ppm)	Basis	NO (ppm)	Basis
Intervane	450	Measured	600	Typical Field
Prototype DMB	100	Extrapolation of Test Results to Design Point	120-150	Rough Estimate

The 120 to 150 ppm NO range corresponds to approximately 59 to 76 ng/J (0.14 to 0.18 lb/10^6 Btu) which is less than the program objective of 82 ng/J (0.2 lb/10^6 Btu). This estimate is, of course, very rough and is based on preliminary test results. An improved estimate will be made as soon as additional prototype burner tests are conducted in the research furnace, and the performance of the host boiler (with Intervane burners) is measured.

As discussed earlier, the prototype DMB tests involve no optimization of either burner geometry or adjustments and resulted in unacceptably high CO levels at the design operating point. Therefore, the "rough estimate" prediction given above is achievable only if modification and optimization of the burner can reduce CO levels in the field boiler typical to those

attainable with the steam generater's original equipment Intervane burners (typically less than 50 ppm).

SECTION 4

SUMMARY

Preparations are underway for the demonstration of the low NO_x DMB concept on two small pulverized coal-fired boilers. Several DMB designs have been tested in research furnaces over a wide range of conditions and nominal design and operating parameters have been identified. These nominal design criteria and the characteristics of the first demonstration boiler have been integrated into a prototype burner design which incorporates commercial burner components. The prototype burner has been briefly tested in the research furnace and additional tests will be conducted to fully evaluate and optimize performance prior to installation in the initial demonstration boiler.

Analysis of test data from the prototype DMB and a commercial burner tested in the research furnace indicates that in the field the DMB flame characteristics will be acceptable. Field NO_x emissions are estimated to be in the range of 59 to 76 ng/J (0.14 to 0.18 lb/10^6 Btu).

Further developmental tests are planned to optimize burner geometry and to ensure that satisfactory stability and combustion efficiency exist over an acceptable range of burner adjustments and normal load and excess air variation. Prior to field installation satisfactory operation, as well as compatibility with commercial ignition and flame scanning equipment, will be demonstrated in the test furnace.

REFERENCES

1. Salvesen, K. G. et al. Emission Characteristics of Stationary NO_x Sources; Volume I Results. EPA Report No. EPA-600/7-78-120A, NTIS No. PB284-540/AS, June 1978.

2. Zallen, D. M. et al. The Generalization of Low Emission Coal Burner Technilogy. In: Proceedings of the Third Stationary Source Combustion Symposium; Volume II Advanced Processes and Special Topics. EPA Report No. EPA-600/7-79-050B, February 1979. pp. 73.

3. Martin, G. B. Field Application of Low NO_x Coal Burners on Industrial and Utility Boilers. In: Proceedings of the Third Stationary Source Combustion Symposium; Volume I Utility, Industrial and Residential Systems. EPA Report No. EPA-600/7-79-050A, February 1979. pp. 213.

4. Gershman, R. et al. Design and Scale-Up of Low Emission Burners for Industrial and Utility Boilers. In: Proceedings of the Second Stationary Source Combustion Symposium; Volume V Addendum. EPA Report No. 600/7-77-073E, July 1977.

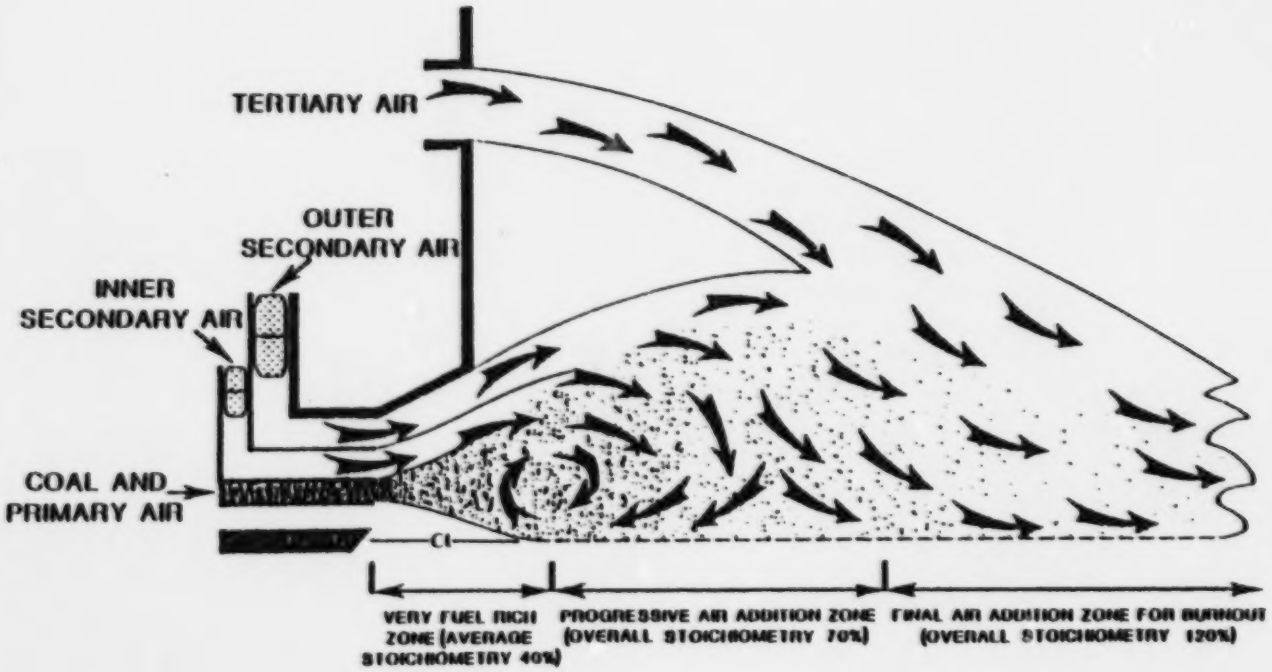


Figure 1. DMB Concept.

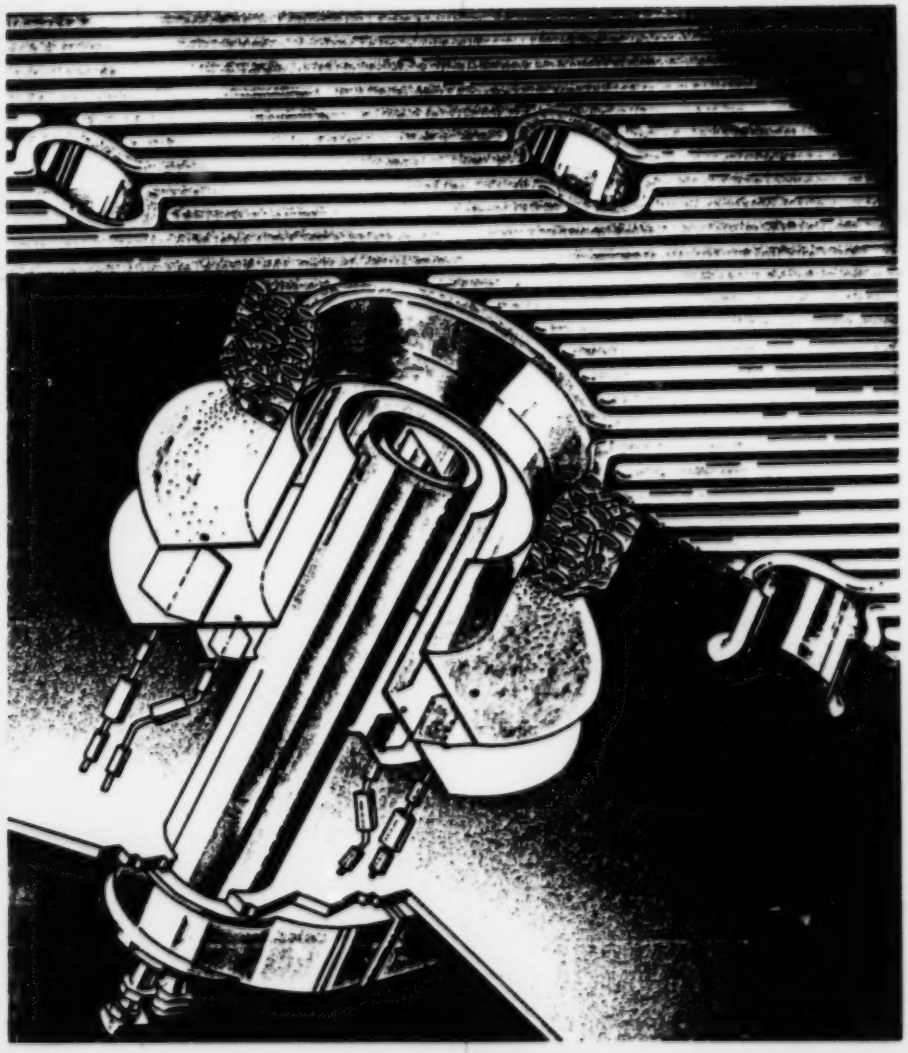


Figure 2. Distributed Mixing Burner.

- 14.6 Thermal MW (50 x 10^6 Btu/Hr) Single Secondary DMB
- Coal = Utah Bituminous
- Load = 14.1 Thermal MW (48 x 10^6 Btu/Hr)
- Overall Stoichiometry = 125% T.A.
- Secondary Swirl Vanes = 45°

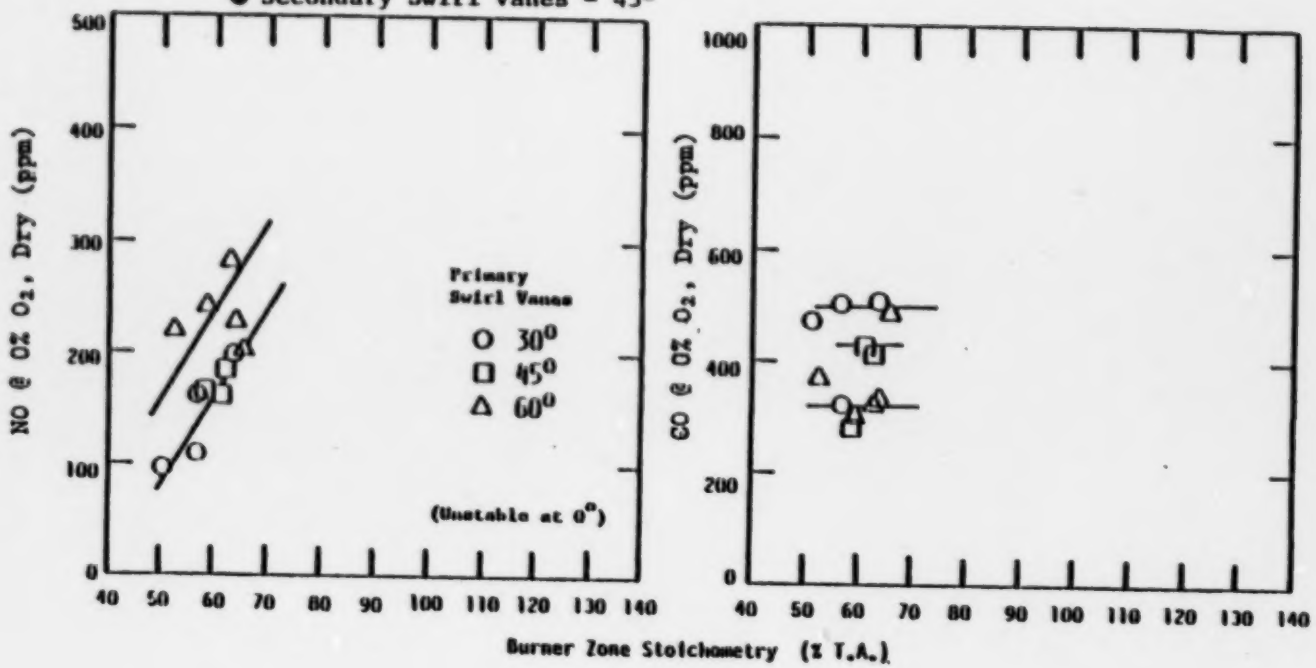


Figure 3. Effects of Fuel System Variables on DMB Performance.

- 14.6 Thermal MW (50 x 10^6 Btu/Hr) Single Secondary DMB
- Coal = Utah Bituminous
- Load = 14.1 Thermal MW (48 x 10^6 Btu/Hr)
- Overall Stoichiometry = 125% T.A.
- Primary Swirl Vanes = 45°

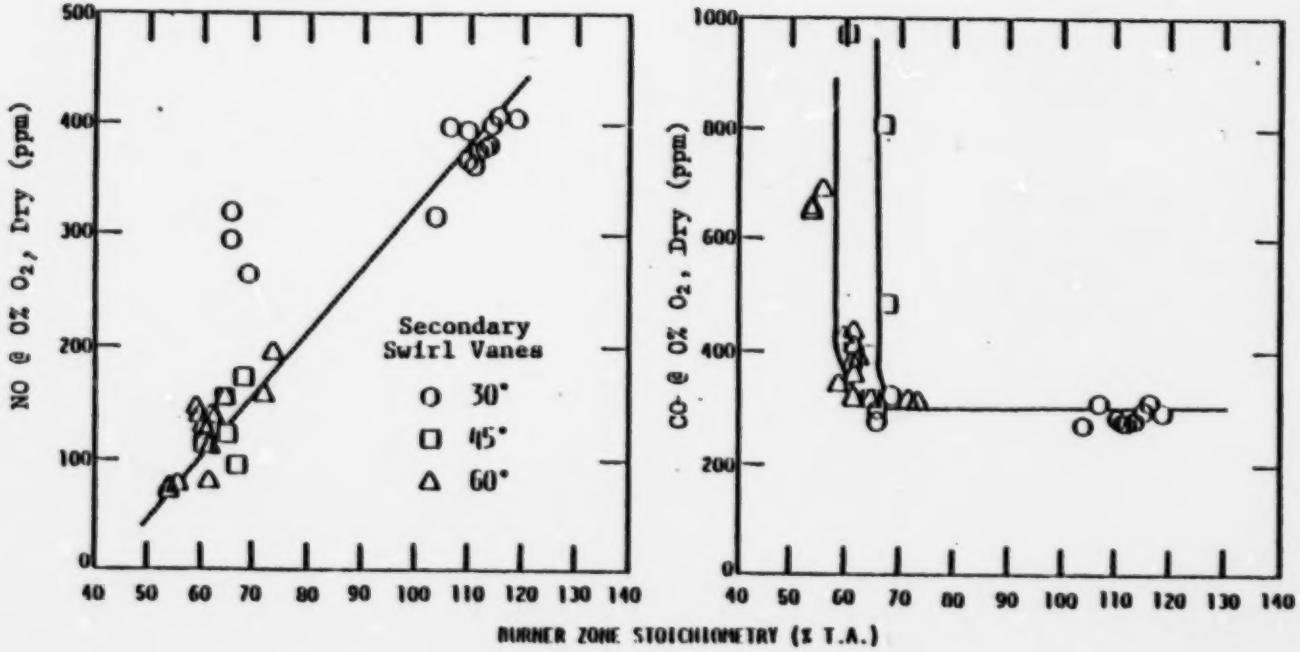


Figure 4. Effects of Secondary Air System Variables on DMB Performance.

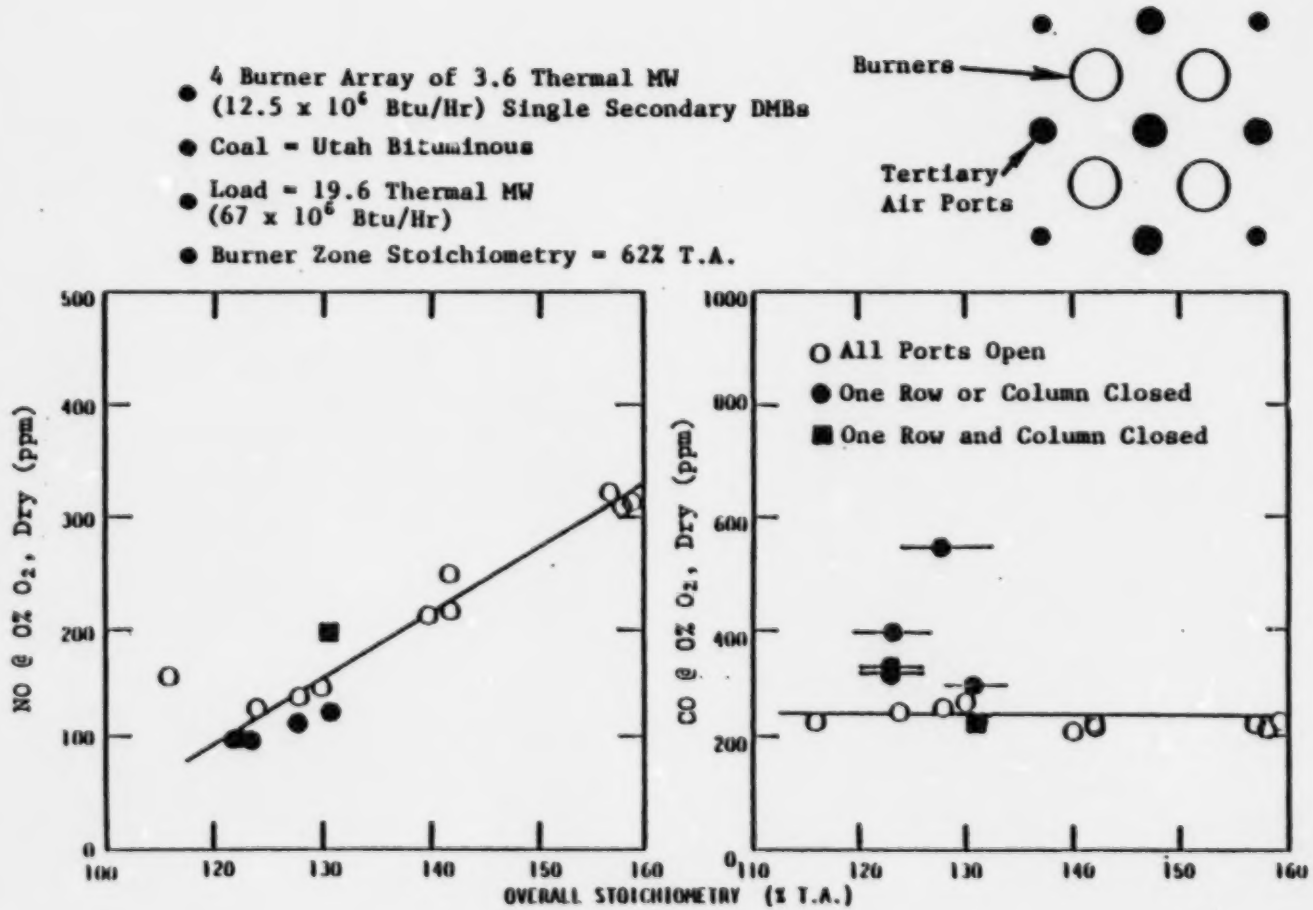


Figure 5. Effects of Tertiary Air System Variables on DMB Performance.

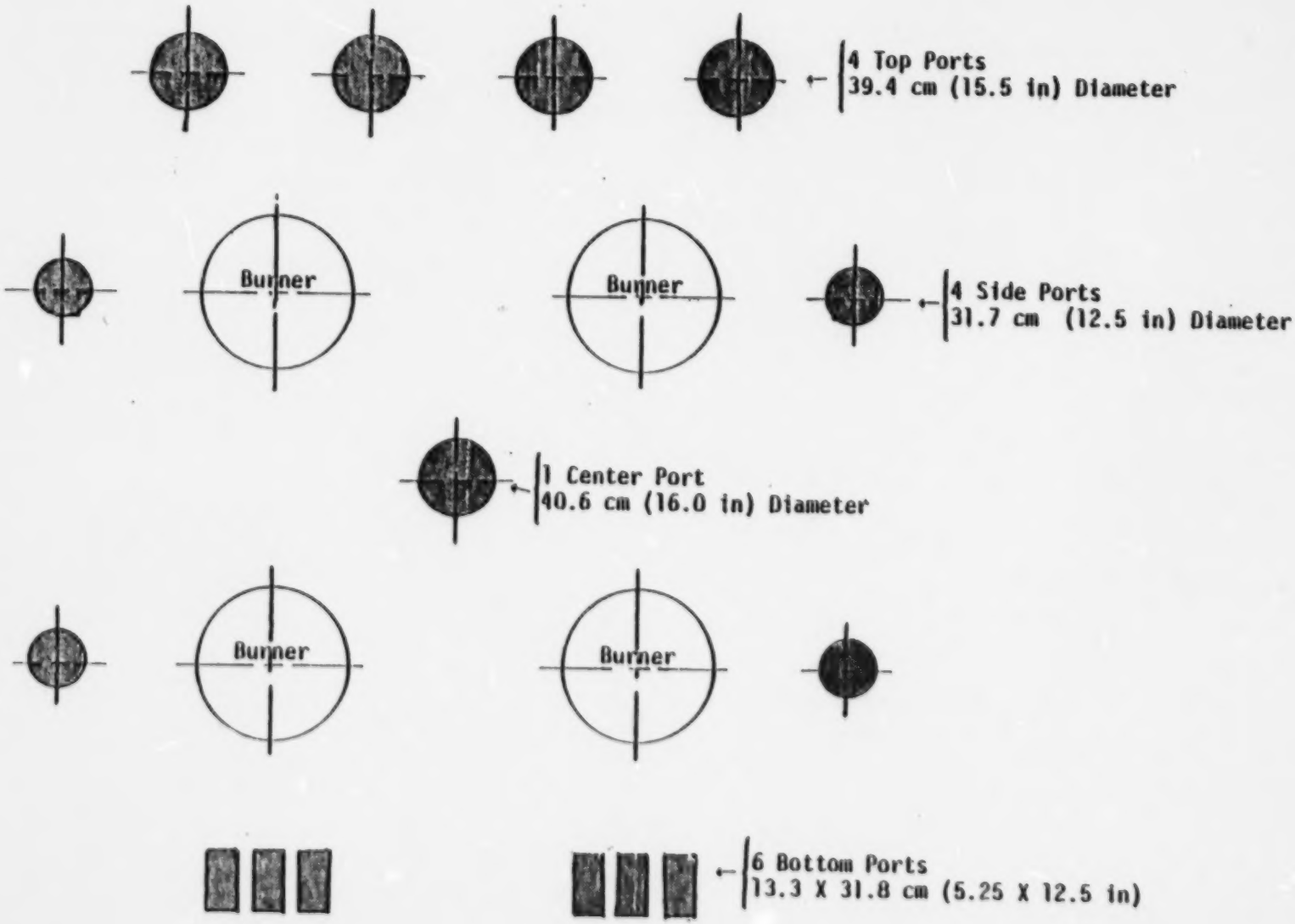


Figure 6. Tertiary Port Configuration for Initial Demonstration Boiler.

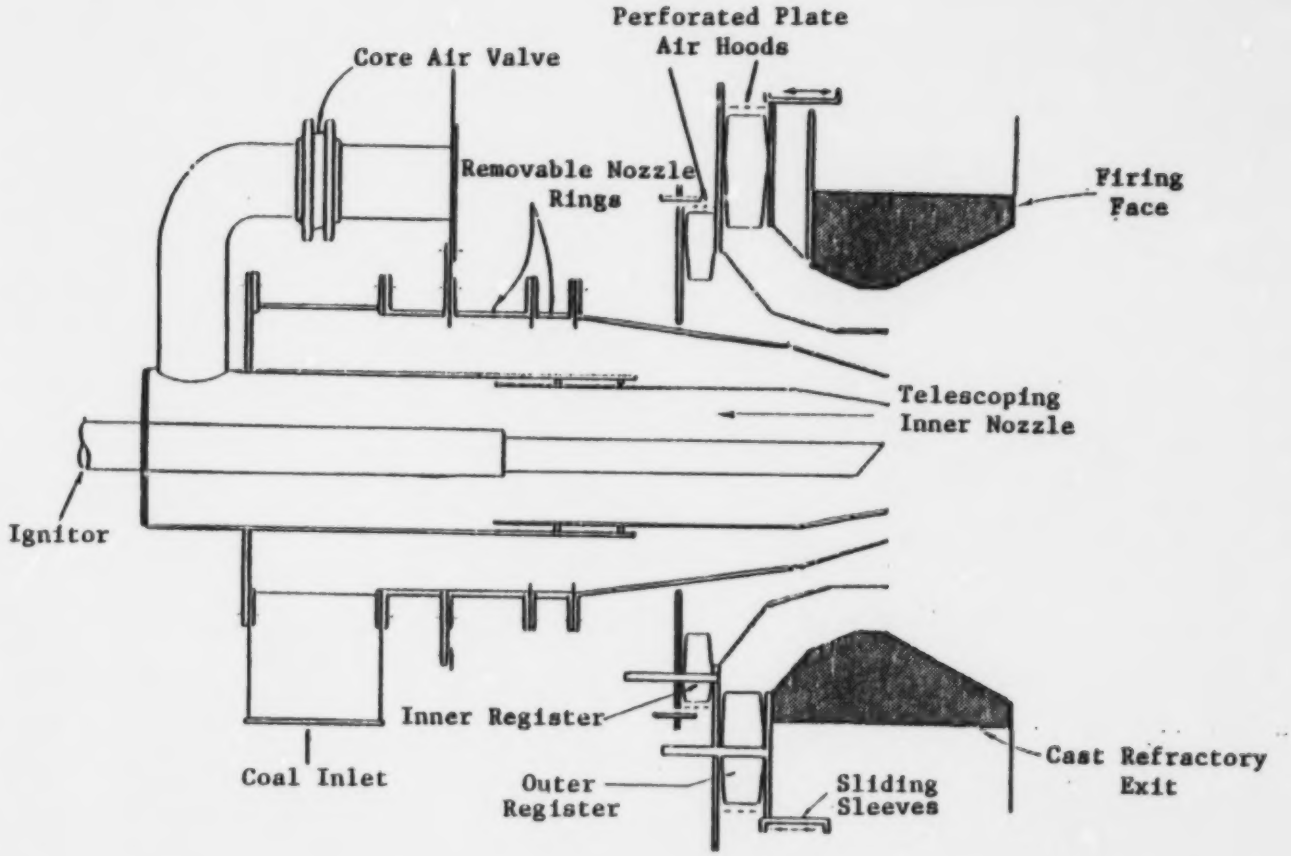


Figure 7. Prototype DMB (Tertiary Ports not Shown).

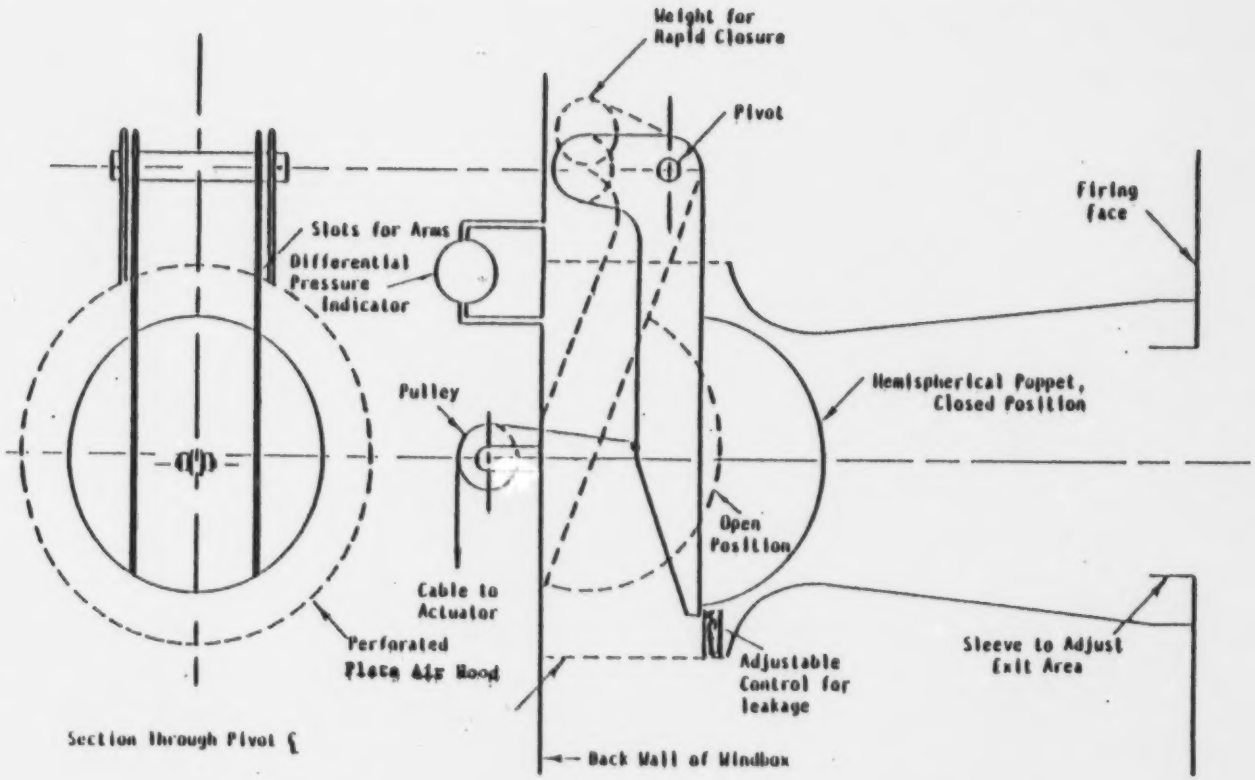


Figure 8. Tertiary Port Control Valve.

Coal = Utah Bituminous

Full Load = 26.4 Thermal MW (90 x 10^6 Btu/Hr)

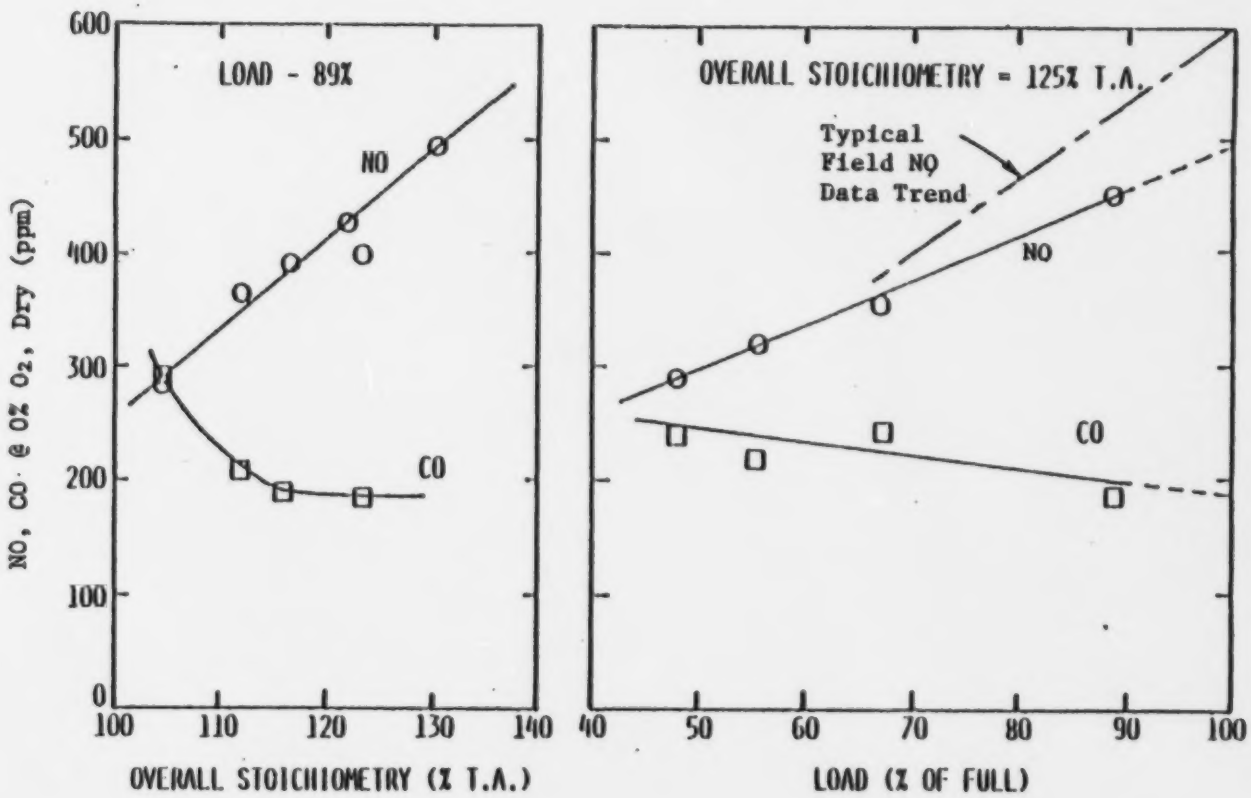


Figure 9. Intervane Burner Performance in Research Furnace.

Coal = Utah Bituminous

Load = 23.4 Thermal MW (80 x 10^6 Btu/Hr)

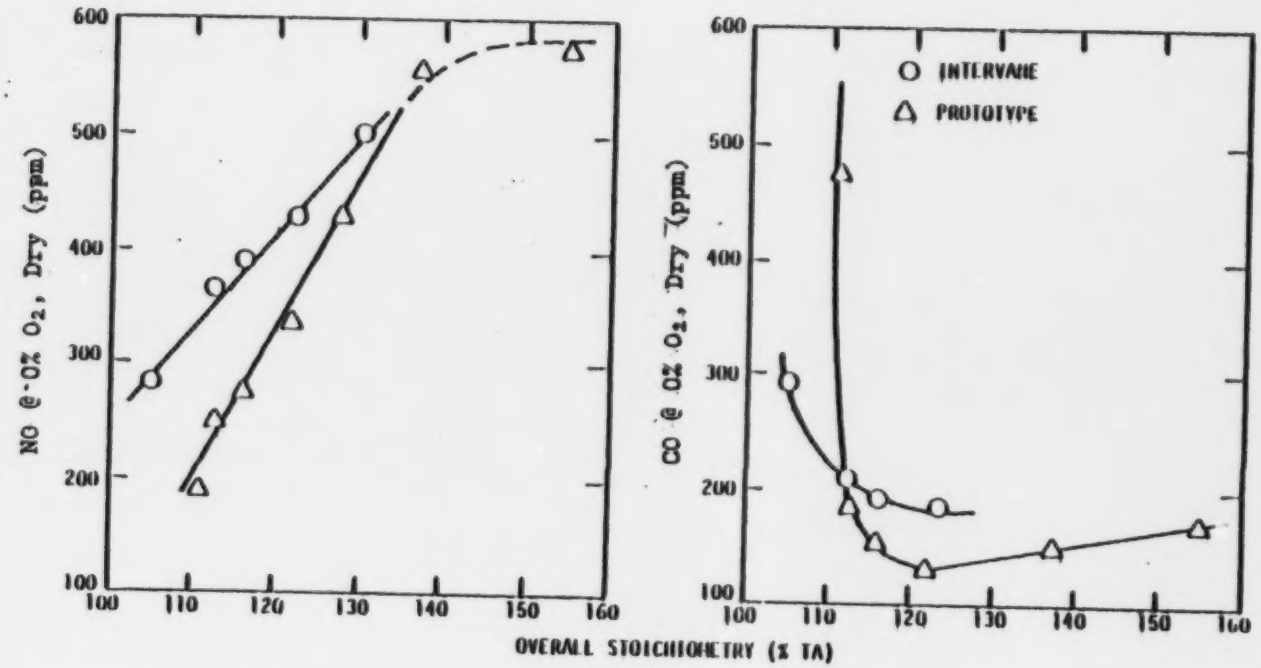


Figure 10. Unstaged Prototype DMB and Intervane Burner Performance in the Research Furnace.

Load = 23.4 Thermal MW
(80 x 10^6 Btu/hr)

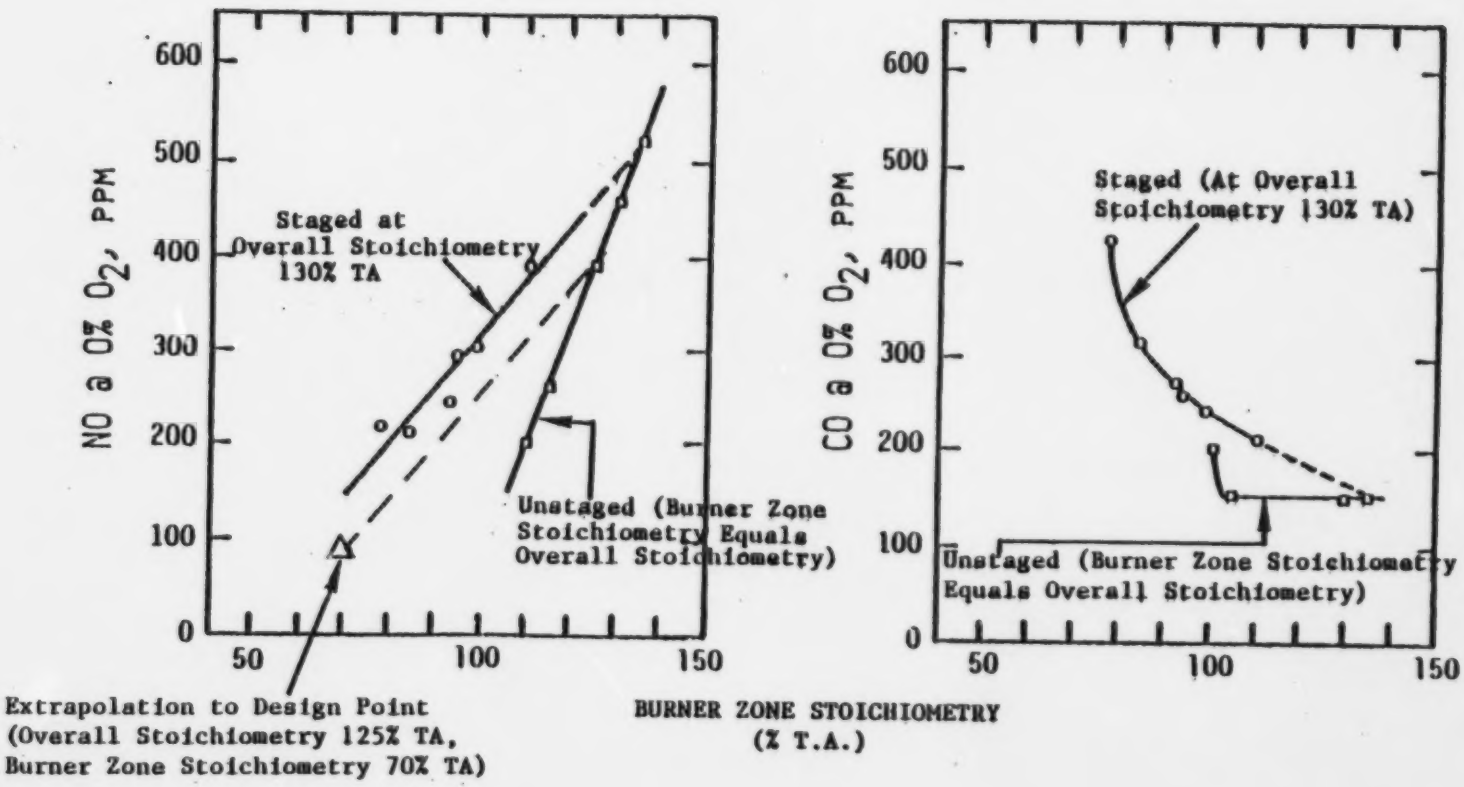


Figure 11. Prototype Burner Performance in Research Furnace.

TABLE I. DMB NOMINAL DESIGN CRITERIA

Burner System	Parameter	Nominal Design Point
Fuel	Swirl	45° Vanes
	Axial Velocity	22.9 m/sec (75 ft/sec)
Secondary Air	Stoichiometry	50-70% T.A.
	Swirl	Variable
	Axial Velocity	18.3 m/sec (60 ft/sec)
Tertiary Air	Number/Shape	4/Round
	Radius/Throat Diameter	2.2
	Velocity	15.2 m/sec (50 ft/sec)
Exit	Half Angle	25°
	Length/Diameter	1.0
	Setback	0

TABLE II. INITIAL DEMONSTRATION SITE CHARACTERISTICS

Parameter		Value
Boiler		
Configuration		Single Wall-Fired
Capacity	MCR	98×10^3 Kg/hr (215×10^3 lb/hr)
	Peak	111×10^3 Kg/hr (245×10^3 lb/hr)
Burners		
Type		Foster Wheeler Intervane
Array		2 x 2
Capacity	MCR	20 Thermal MW (69×10^6 Btu/hr)
Throat Diameter		61 cm (24 in.)
Spacing	Horizontal	182 cm (71.5 in.)
	Vertical	198 cm (78.0 in.)
Furnace		
Construction		Membrane Wall
Depth		6.28 m (20.6 ft)
Width		5.01 m (16.4 ft)
BZLR		492 Thermal kW/m^2 (156×10^3 Btu/hr-ft^2)
Fuel		
Coal Type		Indiana Bituminous
Pulverizers	Type	Foster Wheeler MB
	Number	2
Air Supply		
Air Heater Type		Regenerative
Secondary Air Temperature		265°C (510°F)
Draft		Pressurized
Windbox Depth		132 cm (52 in.)
Burner Pressure Drop (Nominal)		8.9 cm H_2O (3.5 in. H_2O)

TABLE III. INITIAL INDUSTRIAL BOILER DEMONSTRATION SITE COAL CHARACTERISTICS

	As Received	Dry Basis
Proximate Analysis		
% Moisture	13.03	
% Ash	10.14	11.66
% Volatile	36.08	41.49
% Fixed Carbon	40.75	46.85
	100.00	100.00
Ultimate Analysis		
Moisture	13.03	
Carbon	61.30	70.48
Hydrogen	4.36	5.01
Nitrogen	1.30	1.49
Chlorine	0.03	0.04
Sulfur	2.87	3.30
Ash	10.14	11.66
Oxygen (diff)	6.97	8.02
	100.00	100.00

TABLE IV. INDUSTRIAL PROTOTYPE BURNER DIMENSIONS AND ADJUSTMENTS

Design Variable	Nominal* Value	Adjustment Range	Adjustment Method
Fuel Injector			
Core Diameter (in.)	9.75		
Core Area (in.^{2})	74.7		
Nozzle Diameter (in.)	14.5		
Annulus Thickness (in.)	2.375	1.7-3.3	Telescoping Nozzle
Primary Area (in.^{2})	90.5	68-136	Telescoping Nozzle
Setback (in.)	0	-2-+12	Remove/Replace Nozzle Rings
Inner Secondary Channel			
Outer Diameter (in.)	20.75	Variable	Replace Secondary Divider
Annulus Thickness (in.)	3.125	Variable	Replace Secondary Divider
Area (in.^{2})	173.0	Variable	Replace Secondary Divider
Setback (in.)	0	Variable	Replace Secondary Divider
Outer Secondary Channel			
Outer Diameter (in.)	30.25	Variable	Recast Exit
Annulus Thickness (in.)	4.75	Variable	Recast Exit
Area (in.)	380.5	Variable	Recast Exit
Setback (in.)	0	Variable	Recast Exit
Tertiary Ducts			
Distance from Burner ℄ (in.)	53	Variable	Modify Windbox
Spacing Around Burner (deg)	90	Variable	Modify Windbox
Number of Ports	4		
Injection Angle (deg)	0		
Axial Position (in.)	0		
Diameter (in.)	13.25	Variable	Sleeve
Total (in.^{2})	553	Variable	Sleeve
Throat and Exit			
Throat Diameter (in.)	30.25	Variable	Recast Exit
Throat Area (in.)	718.7	Variable	Recast Exit
Half Angle of Exit (deg)	25	Variable	Recast Exit
Length of Exit (in.)	12.0	Variable	Recast Exit
Length/Diameter	0.40	Variable	Recast Exit

*Conversion Factors:

1.0 in. = 2.54 cm
1.0 in.^{2} = 6.45 cm^2

FIELD EVALUATION OF LOW EMISSION COAL BURNER TECHNOLOGY ON A UTILITY BOILER

By:

E. J. Campobenedetto
Babcock & Wilcox Company
Fossil Power Generation Division
Barberton, Ohio 44203

ABSTRACT

A program is currently in progress to demonstrate the NO_x reduction potential of the EPA distributed mixing burner applied to a utility boiler. The demonstration program will be designed to evaluate both emissions attributed to this burner as well as the effects of the burner retrofit on overall boiler performance and efficiency.

The boiler selection process is near completion with a single wall-fired unit being reviewed by the EPA prior to final negotiations. Several opposed-fired units are still under consideration, pending final decisions by the utilities as to their interest in participating in the retrofit demonstration program.

ACKNOWLEDGEMENT

The work presented in this paper was performed as part of the Utility Boiler Field Evaluation of Low Emission Coal Burner Technology Program funded under EPA contract 68-02-3130. The contract is sponsored by the Industrial Environmental Research Laboratory, Combustion Research Branch. The author acknowledges the assistance of the EPA Project Officer, G.B. Martin and the Energy and Environmental Research Corp. in the planning stages of this program.

INTRODUCTION

The Environmental Protection Agency has regulated the emissions of nitrogen oxides (NO_x) from utility boilers sold and erected since 1971 through enactment of the New Source Performance Standards. The Clean Air Act Amendments of 1977 required the EPA to review and revise the NSPS at four year intervals. The 1978 revisions lowered the NSPS for NO_x emissions from utility boilers and it is anticipated that further reductions in the maximum allowable emission level of NO_x will occur. In addition, utilities in NO_x non-attainment areas could be required to retrofit NO_x control equipment to existing units as part of the state implementation plans.

The EPA has developed a low emissions burner to provide for optimum reductions in NO_x levels produced during the combustion of pulverized coal. The development of this low emission coal burner technology began in 1970 under a contract with the International Flame Research Foundation in an attempt to characterize the effects of burner design parameters on NO_x emissions from pulverized coal combustion[1]. The results of this and further studies indicated that the levels of NO_x could be controlled to low levels through combustion modifications.

A nine task contract was awarded to the Babcock and Wilcox Co. in 1978 to demonstrate the use of this technology on a multiple burner utility boiler. The purpose of this paper is to highlight the program and to describe the progress to date in the areas of the boiler selection and the burner design.

TEST PLAN STRUCTURE

The objective of the program is to evaluate the EPA low emission coal burner on a multiple burner utility boiler. The evaluation will attempt to determine the lowest practical NO_x limit under normal operating conditions without a sacrifice in boiler availability, performance, or efficiency. The program consists of nine tasks as detailed below:

TASK	DESCRIPTION
1.0	Program Definition
2.0	Prototype Fabrication & Testing
3.0	Host Boiler Baseline Evaluation
4.0	Burner Fabrication & Installation
5.0	Unit Performance Evaluation
6.0	Industry Coordination Panel
7.0	Unit Restoration
8.0	Data Analysis
9.0	Guideline Preparation & Reports

A brief description of each task is provided below:

1.0 PROGRAM DEFINITION

This task provides for the initial planning and management plan for the overall program effort. The task is divided into four subtasks to provide planning in each of the major areas of the initial program plan. The subtasks are: 1.1 Boiler Selection, 1.2 Burner Engineering Design, 1.3 Analytical Measurements Plan, and 1.4 Overall Program Plan.

1.1 Boiler Selection

The prime purpose of this subtask is to identify and select an existing unit to retrofit and evaluate the distributed mixing burner. The unit selection is based on willingness of the utility to participate as well as the state-of-the-art for pulverized coal firing as applied to utility boilers both in the existing population and the current new boiler market. Based on the above, a detailed selection criteria was established to evaluate potential candidate boilers. The utilities were then contacted to determine interest in the program. A detailed summary of the site selection process will be presented later in the paper.

1.2 Burner Engineering Design

The experimental data on the low emissions burner was reviewed to establish the optimum design criteria for the prototype

burner and subsequent retrofit burner. This information will be incorporated with the site specific requirements of the unit selected to finalize the prototype burner design. Also included in the resultant design package will be the specifications for the auxiliary equipment required for the retrofit and any constraints placed on the burner design due to the limitations of the existing boiler.

1.3 Analytical Measurements Plan

In this subtask, the overall approach for evaluation of the emissions resulting from this burner will be defined. In addition, the entire boiler performance evaluation program will be established in the performance of this subtask. It is essential that both boiler performance and emissions data be collected simultaneously to determine the overall performance of the distributed mixing burner system vs. the existing burner system which will be characterized during the boiler baseline evaluation.

Energy and Environmental Research Corporation, EER, as a subcontractor to B&W has the lead responsibility in the development of the Analytical Measurements Plan for monitoring pollutant emissions. This structure will provide for consistency between the Industrial and Utility emissions monitoring programs. Also, EER will establish the overall procedures necessary to satisfy the requirements established by the EPA's Office of Air Quality

Planning and Standards. Further discussions of the Analytical Measurements Plan will be presented by EER.

1.4 Overall Program Plan

The results of the above subtasks will be incorporated into a final program plan detailing the performance of the remainder of the burner evaluation program. The plan will be based on the selection of a boiler and the resultant outage schedule, burner design, and measurements plan established for the specific unit. This plan will be reviewed and revised periodically, as required, to insure successful completion of the demonstration program.

2.0 PROTOTYPE FABRICATION AND TESTING

A prototype burner will be fabricated based on the results of Subtask 1.2 detailed above. The prototype burner will be a full size burner of the design to be installed in the host boiler. This burner will be installed in the EPA's large watertube simulator (LWS) to verify the performance of the burner prior to finalization of the design and fabrication of the multiple burners required for the field demonstration. Tests will be performed to evaluate the burner performance over a range of operating conditions and with several coal types (including the coal to be burned during the utility demonstration) to compare the results with those obtained during the experimental burner test programs. A burner of the design currently utilized on the selected utility unit will also be fabricated and tested on the

LWS for comparison of emissions and burner performance.

3.0 HOST BOILER BASELINE EVALUATION

The baseline evaluation will consist of 4-6 weeks of boiler testing prior to any modifications. These tests will provide a data base for direct comparison of the distributed mixing burner. The data to be collected will be used to evaluate overall system performance, unit efficiency, and pollutant emissions. A continuous monitoring system will be utilized to collect the gaseous emissions data. The data will be collected over the normal operating range of the boiler to characterize the combustion system currently installed. Parameters to be varied and reviewed will be boiler load, burner configuration, excess air levels, and burner zone liberation rate.

4.0 BURNER FABRICATION AND INSTALLATION

The prototype testing will culminate in a final design package for the burner system to be applied in the field. When the final design package has been approved by the EPA and the utility, the required number of burners will be fabricated and shipped to the site. All required auxiliary equipment will also be fabricated or purchased during this period. The above equipment will be installed in the unit during an outage scheduled by the utility.

At the completion of the outage, the boiler system will proceed through a normal start-up sequence. All burner settings will be

determined and preliminary tests will be performed to insure that overall operation of the unit over its normal load range has not been adversely affected by the retrofit.

5.0 UNIT PERFORMANCE EVALUATION

At the completion of the burner system start-up, the performance evaluation program will commence. The first step in the program will be burner system optimization tests. Burner settings will be varied to determine the optimum settings for burner stability, carbon utilization, and minimization of gaseous pollutant emissions. The final burner settings to be utilized during the long term evaluation program will be established during this period.

The eighteen (18) month unit performance evaluation will begin after the optimization tests are complete. Emissions data will be collected on a continuous basis throughout the demonstration. In addition, detailed measurements of boiler performance and emissions will be conducted during the initial 30 day period of operation and during the eighteenth months of operation. These detailed measurements will be repeated periodically throughout the program to evaluate the long term operation of the burner system.

6.0 INDUSTRY COORDINATION PANEL

The purpose of this task is to secure the advice of manufacturers and users of pulverized coal burners on the practical aspects of the

technology and to assure the timely dissemination of the developing technology to the potential users. The technical advisory panel established includes potential users, boiler and burner manufacturers, representatives of research and academic organizations involved in coal combustion studies, and members of the EPA's Combustion Research Branch. The members of this panel review all aspects of the experimental programs as well as the industrial and utility programs to facilitate the technology transfer through the various stages of development for the distributed mixing burner.

7.0 UNIT RESTORATION

At the completion of the testing period, the boiler will be restored to its original configuration during an outage scheduled by the host utility. At the completion of the site restoration, the system will then proceed through a normal start-up to insure that the unit is operating in a mode acceptable to the utility.

8.0 DATA ANALYSIS

The boiler and emissions data collected throughout the test program (prototype, baseline, and retrofit) will be analyzed and tabulated continuously throughout the program to provide the input to direct the ongoing program. The data will be analyzed to evaluate overall system performance, emissions, and the effects of low emissions operation on boiler performance. The specific analyses include:

1) Comparison of the experimental and prototype burner data to identify the optimum design for the retrofit burner.

2) Comparison of the prototype and existing host boiler equipment in the LWS to provide an estimate of the performance of the distributed mixing burner in the host boiler.

3) Evaluation of the baseline data to determine the existing performance and emissions from the unit. This will provide a reference point to evaluate the benefits of the distributed mixing burner.

4) Evaluation of the burner settings during the optimization stage to determine the flexiblity of the burner performance in meeting low NO_x over the normal load range of the utility boiler while maintaining acceptable system performance as evaluated against the baseline tests.

5) Continuous review of the long term burner performance to document any changes in emissions or unit efficiency due to fuel changes or burner system deterioration. This analysis program will provide input to the ongoing design review to identify potential design modifications required to apply this technology to the wide range of wall fired boilers both as a retrofit and as an application to new units. The data will be evaluated utilizing the baseline data as well as the burner evaluation techniques

developed by B&W for evaluating NO_x emissions and boiler performance to generalize the technology for future applications.

9.0 GUIDELINE PREPARATION AND REPORTS

A guideline manual will be compiled at the completion of the test program to summarize the results of the design study, field tests, and the overall data evaluation. The manual will provide a forum to present the program results and problems and solutions to the manufacturers and utilities and will be used to assess the potential applicability of this low NO_x system on a commercial basis.

The manual will include:

1) Final design information for the prototype and field burners.

2) Design problems that must be addressed for various fuels.

3) Data summaries for each phase of the burner development program (experimental, prototype, baseline, and retrofit).

4) Prediction curves developed for application of this technology to utility boilers.

5) Functional and mechanical operation of the burner, including problems that developed and the solutions employed to rectify

the problems.

6) Effect of the low NO_x operating conditions on boiler performance and other pollutants monitored throughout the program.

7) Parameters to optimize to obtain system performance equivalent to the baseline performance.

8) Benefits and detriments of this method of low NO_x operation compared to other proven NO_x control methods.

PROGRAM STATUS

The major effort for this program has been in the development of the overall plan leading to a prototype test and subsequent field demonstration. The two major items leading to conclusion of the planning stage were selection of a suitable host site and development of the preliminary distributed mixing burner design package for the host site selected.

The following section summarizes the work leading to the boiler selection and preliminary burner design:

Boiler Selection

The two major factors in establishing the host site selection criteria were: 1) The unit selected was representative of a large segment of the existing population of units or of current designs being sold and, 2) The economics of a retrofit of this magnitude must be evaluated to establish a maximum boiler size. Based on the above, the initial criteria was established to evaluate opposed fired units less than 300 MWe capacity. The final selection criteria and prioritization schedule were established after a review of the trends in fossil-fired utility boilers.

A) History

Over the past ten years, the trend in the electric utility fossil-fired population has been to coal fired units. This shift to coal has been caused by the economics of coal vs. oil as well as the uncertainty of oil supply from the Middle-East. Figures 1 and 2 provide a summary of the fossil-fired plant orders for the electric utilities. Since 1975, virtually all units sold have been designed for pulverized coal. The percentages shown in Figure 1 are somewhat low because the "coal only" megawatts do not include the units designed for fuel combinations (coal/oil/ gas) as shown in Figure 2. In addition, the Fuel Use Act of 1978 prohibits the use of natural gas or petroleum products as a primary fuel for a utility boiler.

The average size of an electric utility boiler has also increased significantly over the past twenty years. Figure 3 indicates the trend in boiler size. In 1960, the average size unit place in service was 133 MW with the largest unit being 500 MW. This average stayed fairly constant through the mid-1960's. From 1965 on, the average size of the steam generating units placed in service by the electric utility industry increased steadily. Today, the average size unit is about 500 MW. The largest units in service are rated at 1300 MW.

Figure 4 provides an indication of the distribution pattern by size of operating boilers as of 1979. As indicated, the majority of

the units (65%) are less than 250 MW. In addition, most of these units are one wall fired due to their size. However, with the trend toward larger units, the majority of the units sold today are opposed-fired units. A review of firing pattern and unit size of operating B&W utility boilers is provided in Figure 5. As previously stated the majority of the units are one wall-fired units (ranging in size to about 250 MW maximum). The opposed fired units in the size range initially established (300 MW maximum) represent a very small segment (7.98%) of the existing population. Although the one wall-fired units represent almost half of the total operating units, the one wall and small opposed-fired units represent a very small portion of the total steaming capacity of the electric utility boiler population (14.1%).

In addition to the overall boiler population, a review of the B&W furnace design criteria relating to NO_x was also performed. The two factors evaluated were the burner zone heat release rate (HA/SC_1) and the burner input. Figure 6 provides a summary of the changes in HA/SC_1 as NO_x emission limits became a factor in boiler design. Prior to promulgation of the New Source Performance Standards (NSPS) of 1971, the burner zone heat release rate for the larger units averaged between 700-800 KBtu/ HR-FT^2. Field tests of these units indicated a direct correlation between this parameter and NO_x emissions for a given burner system. The HA/SC_1 was reduced to the range of 400-500 KBtu/HR-FT^2 in 1971 to meet the NOx emission levels established by the 1971 NSPS. Currently, the average boiler is designed with a

HA/SC_1 of 350-450 KBtu/HR-FT^2 to meet the 1978 NSPS NO_x emission levels.

The burner heat input has remained constant although the pulverized burner design has changed significantly for NO_x considerations. The burner input has remained in the range of 100-135 x 10^6 Btu/HR as shown in Figure 7. The standard burner designed by B&W has a nominal input of 125 x 10^6 Btu/HR and varies in the above range based on matching of the number of pulverizers and burners required. For the smaller units, the burner input can be as low as 75 x 10^6 Btu/HR again dependent on the matching of the required number of pulverizers and burners.

B) Selection Criteria

The preliminary selection criteria which was established based on the above review was as follows:

- Unit Size - 350 MW Maximum
- Burner Zone Heat Release Rate - 500 KBtu/HR-FT^2 Maximum
- Firing Mode - Opposed Wall
- Burner Type - B&W Circular or Dual Register
- Fuel - Pulverized Coal

The initial list of potential units which fit the above criteria was assembled and is shown in Figure 8. These units were considered

as the prime potential candidates for the burner retrofit program. As the initial contacts were made, however, the responses received from the utilities detailed above indicated minimum interest in a program of this magnitude. In general, the responses from the utilities were as follows:

- The unit under consideration by B&W was a base loaded unit and the utility could not risk an experimental program on a unit which was the heart of their system.

- With the generating capacity constraints what they are today, the utility could not afford an extended outage to retrofit the combustion equipment to their boiler.

- The utility could not risk deterioration of unit performance or a loss of availability or reliability for the unit as is possible with an experimental program.

- Utilities were very reluctant to cooperate with the EPA on a program which could adversely impact future boiler designs with additional constraints on pollutant emissions. This concern not only included NO_x but carbon monoxide, hydrocarbons, fine particulate, and trace elements which will be determined throughout the program.

- Inadequate space was available in the burner zone to fit the burner/tertiary air port configuration required. Burner-to-burner side and vertical spacings were not adequate for the installation of the required DMB hardware.

As a result of this response, the initial candidate list was expanded and a selection prioritization schedule was developed. This unit prioritization is detailed in Figure 9. The initial seven (7) units under review represented categories 1 and 2. Several larger units, up to 750 MW were reviewed as potential candidates with the same results as described above. A comparison of the design parameters of several of these units are detailed in Figures 10 and 11. All units to this point were opposed fired units.

The next series of units for review were the single wall-fired units. Based on a review of several units, discussions were held with several utilities that were interested in the program. These discussions led to three units which the utilities were willing to commit to this program. The design parameters for these three units are shown in Figure 12. Based on this review, unit 3 was eliminated because it was too small (75 MW). In the design review of units 1 and 2, it was determined that unit 2 would be more difficult to retrofit because of obstructions in the windbox which could cause improper airflow distribution to the tertiary air ports. Therefore, it was determined that unit 1, a 175 MW unit operated by Northern States Power (NSP) would be the prime candidate for the EPA low NO_x burner retrofit.

This unit, located at NSP's Highbridge Station, has a maximum capacity of 1,200 MLB/HR main steam flow and is currently equipped with 16 circular burners arranged in a 4 x 4 matrix on the front wall. The burner zone is 48 feet wide by 21 feet deep. The unit was originally designed for an Illinois high sulfur coal, but currently burns a blend of Illinois and Montana coals for SO_2 emission considerations. A sketch of this unit is shown in Figure 13.

NSP has consented to participate and negotiations are continuing pending approval of this unit by the EPA Project Officer.

In addition, discussions are still continuing with utilities which are operating the larger, opposed-fired units to determine if an opposed fired unit can be made available for this demonstration.

Burner Design

A preliminary burner design was developed during the early stages of the contract. This was established based on a nominal 125×10^6 Btu/HR burner input. A general set of criteria was established to identify the practical requirements for the low NO_x burner retrofit. These criteria are identified in Figure 14. These criteria are based on the practical limitations of pulverized coal combustion and will be used to evaluate the success of this burner retrofit along with the NO_x reduction potential of the burner.

The final design specifications for the prototype and field retrofit burners will be established based on the requirements of the host boiler selected. A preliminary design, based on the experimental results obtained by EER, the current B&W design limits, and a nominal 125 x 10^6 Btu/HR burner are detailed in Figure 15. Figure 16 is the preliminary sketch of the prototype burner design based on the design specifications detailed above.

One problem that has narrowed the field of potential host boilers has been the burner spacing on several units under preliminary review. To fit the tertiary ports around the burners, there must be adequate clearances to install the ports and the required airflow control systems while maintaining an adequate number of straight tubes in the furnace walls for support. Several units under review had inadequate burner to burner spacings to even consider the retrofit program.

Another problem that has developed is the problem of retrofitting this burner design to an operating unit. Besides the burner design, it appears that major revisions to the structural supports in the windbox will be required to install this burner. Also a stress review of any unit under consideration must also be made to evaluate the structural integrity of the furnace wall after bending all the additional furnace wall tubes required to form the tertiary air ports. At present, these studies have not been pursued in detail pending final approval of the host boiler by EPA.

After approval has been received, a complete evaluation of the unit will be performed to determine the modifications to the boiler and supports required to retrofit this low NO_x burner.

CONCLUSIONS

- A tentative host boiler has been selected at Northern States Power's Highbridge Station.

- The utility burner retrofit program is behind schedule due to delays in obtaining a host site.

- The current schedule, pending EPA approval, is to start the demonstration program late in 1981.

- The retrofit will be more difficult than originally anticipated due to the structural modifications required to install the burner and tertiary air ports.

- Efforts are still proceeding to locate a utility operating a small opposed-fired B&W boiler for possible participation in this program.

REFERENCES

1. Martin, G.B., "Field evaluations of Low NO_x Coal Burners on Industrial and Utility Boilers". Presented at the Third Stationary Source Combustion Symposium, San Francisco, California, March 5-8, 1979.

2. Kidder, Peabody & Company, Fossil Boilers Status Reports.

3. EBASCo, 1979 Business and Economic Charts.

4. Heil, T.C. & Durrant, O.W., "Designing Boilers for Western Coal". Presented at the Joint Power Generation Conference, Dallas, Texas; September 10-13, 1978.

PLANT ORDERS (MWE) IN THE U.S.
BY ELECTRIC UTILITIES[2]

BOILERS

YEAR	COAL ONLY	TOTAL FOSSIL**	COAL AS % OF TOTAL FOSSIL
1963	5,103	13,767	37.1
1964	4,684	15,535	30.2
1965	13,435	21,613	62.2
1966	13,242	20,797	63.7
1967	14,006	24,975	56.1
1968	13,383	22,810	58.7
1969	18,720	27,012	69.3
1970	12,234	29.635	41.3
1971	6,784	15,817	42.9
1972	9,424	16,956	55.6
1973	21,434	26,605	80.6
1974	29,438	32,522	90.5
1975	7,281	7,690	94.7
1976	5,318	6,018	88.4
1977	12,373	12,431	99.5
1978	13,457	14,424	93.3
1979	5,467	5,467	100.0

**GAS, OIL, OR COAL (OR SOME COMBINATION THEREOF).

FIGURE 1

NUMBER OF FOSSIL BOILER ORDERS BY ELECTRIC UTILITIES[2]

YEAR	GAS	OIL	GAS/OIL	OIL/COAL	COAL, OIL & GAS	COAL
1969	3	6	9	-	6	29
1970	2	16	11	-	8	24
1971	1	11	3	-	4	15
1972	-	10	4	2	7	20
1973	-	4	3	-	5	38
1974	-	-	4	-	7	60
1975	-	-	1	-	1	14
1976	-	-	-	-	1	12
1977	-	1	-	-	-	24
1978	-	-	-	-	3	27
1979	-	-	-	-	-	14

NOTE: THIS TABLE INDICATES THAT MOST OF THE FUTURE ORDERS OF FOSSIL BOILERS FOR THE ELCTRIC UTILITY INDUSTRY WILL BE FUELED BY COAL.

FIGURE 2

STEAM-ELECTRIC GENERATING UNITS
PLACED IN SERVICE
BY THE ELECTRIC UTILITY INDUSTRY[3]

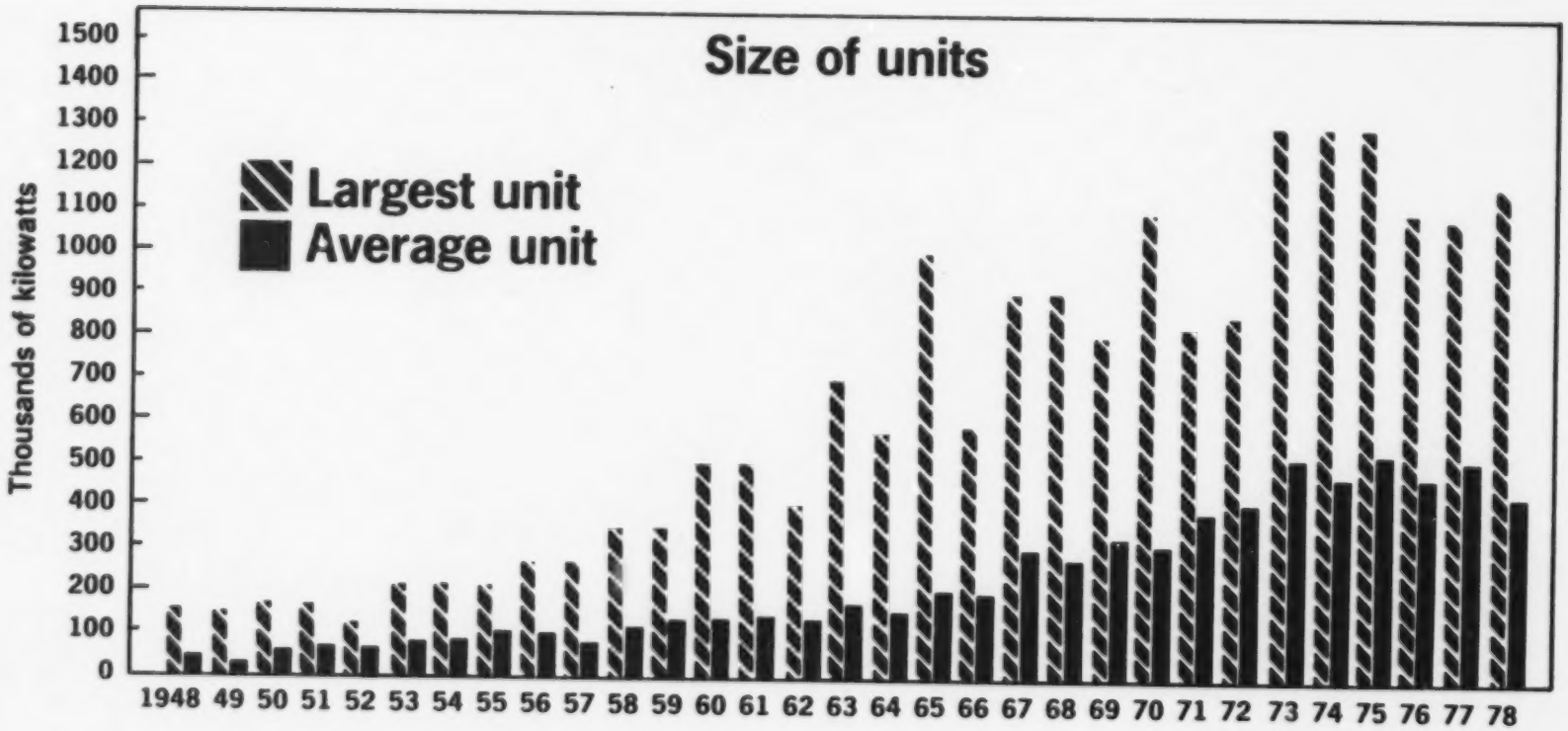


FIGURE 3

DISTRIBUTION PATTERN OF COAL FIRED UNITS
IN SERVICE IN THE U.S. IN EARLY 1979 [2]

RANGE (MW)	NUMBER OF UNITS COAL
50-250	481
250-450	130
450-650	76
650-850	45
850-1050	2
1050-1250	3
1250-1450	5

FIGURE 4

FIRING PATTERN & UNIT SIZE DISTRIBUTION

	% BY UNITS	% STEAM FLOW
ONE WALL FIRED UNITS	42.9	8.8
OPPOSED-LESS THAN 300 MW	8.0	5.3
OPPOSED-300 TO 600 MW	22.3	27.7
OPPOSED-GREATER THAN 600 MW	26.8	58.2

FIGURE 5

PULVERIZED COAL FIRED BOILER EXPERIENCE[4]

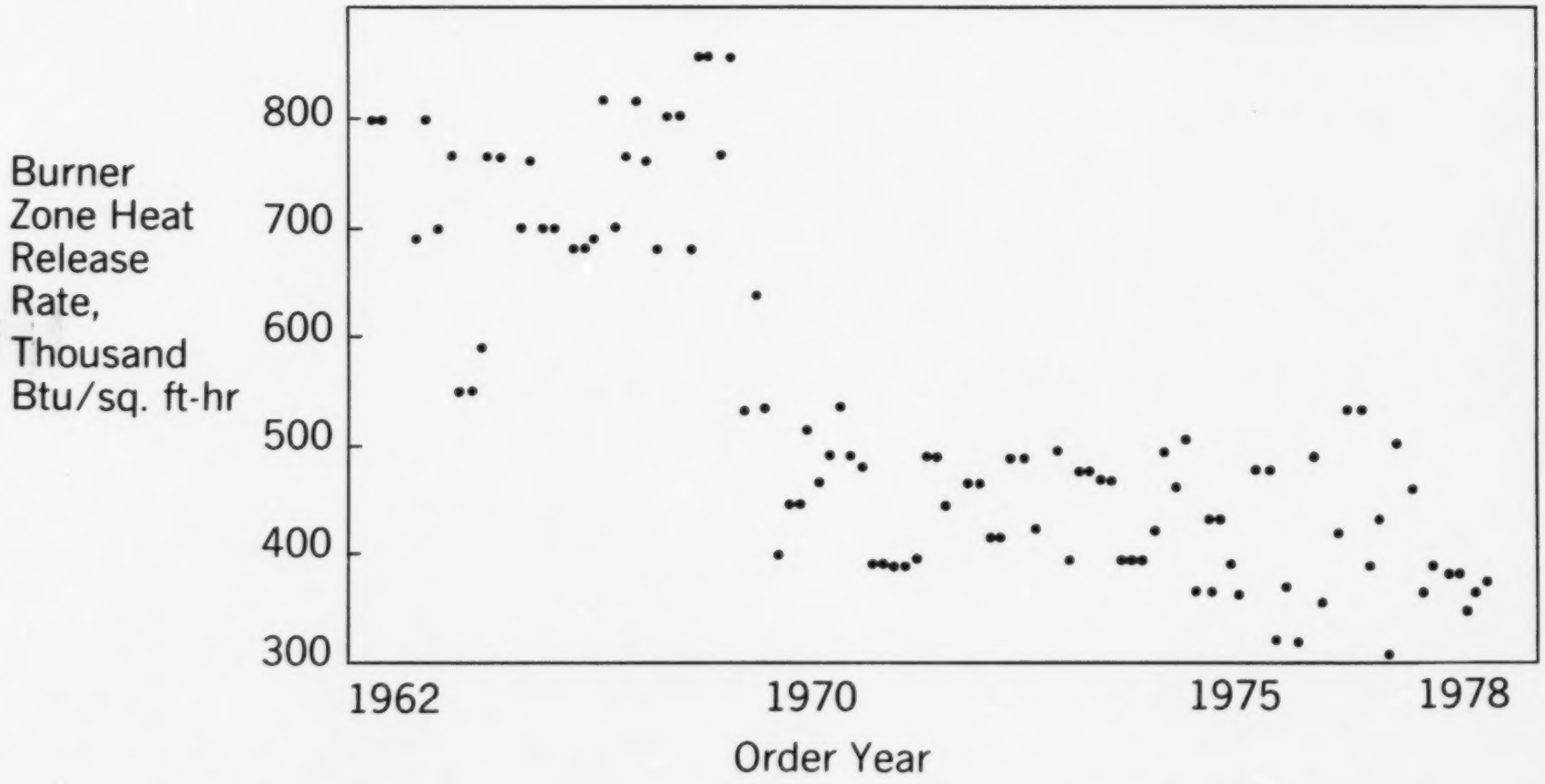


FIGURE 6

PULVERIZED COAL FIRED BOILER EXPERIENCE[4]

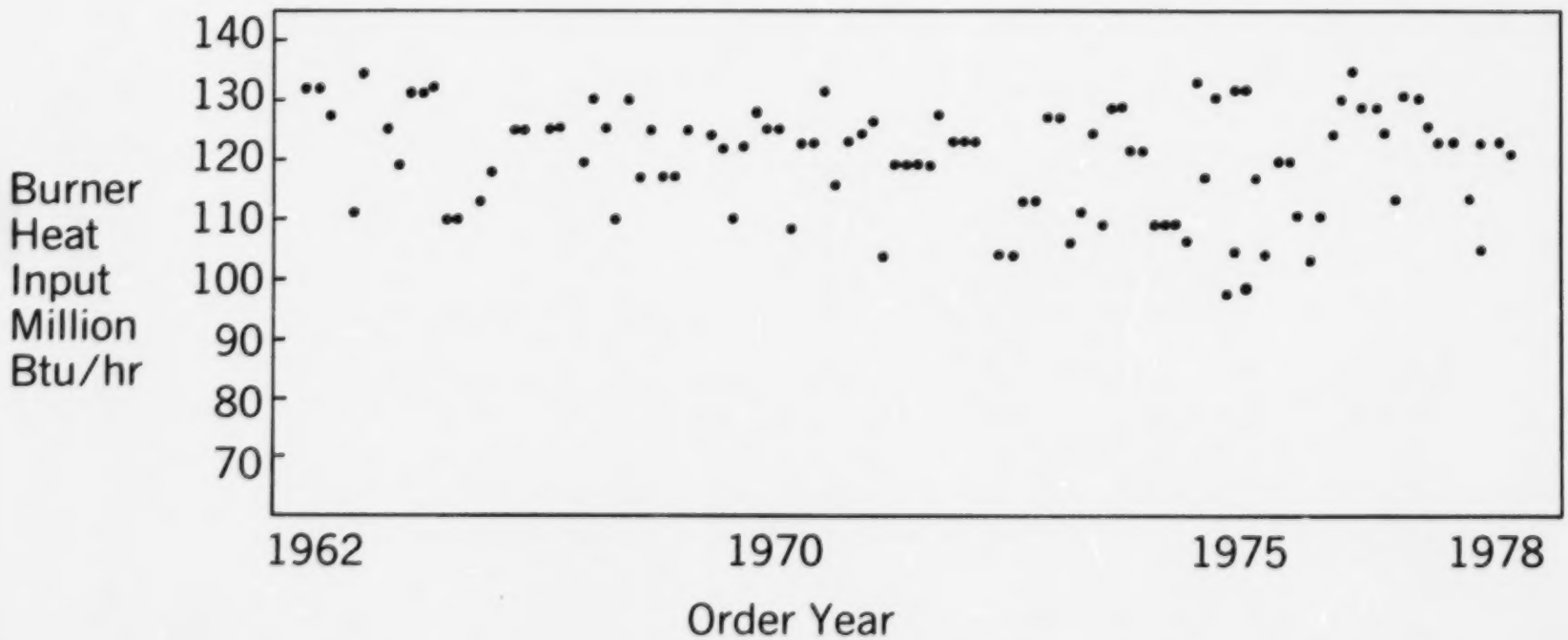


FIGURE 7

POTENTIAL HOST SITE CANDIDATES

UTILITY	SIZE MW	HEAT RELEASE RATE	BURNER PATTERN	BURNER TYPE	NUMBER OF BURNERS	COAL TYPE	NOx PORTS
A	350	384	OPPOSED	CIRCULAR	32	SUBBIT.	YES
B	333	508	"	DUAL REG.	24	BIT.	NO
C	265	502	"	CIRCULAR	18	BIT.	NO
D	250	325	"	CIRCULAR DUAL REG.	18	BIT.	NO
E	250	299	"	CIRCULAR	24	BIT.	NO
F	350	390	"	DUAL REG.	30	SUBBIT.	NO
G	216	342	"	CIRCULAR	20	LIGNITE	NO

FIGURE 8

SELECTION PRIORITIZATION

- NEW UNITS - REPRESENTATIVE OF CURRENT DESIGNS
- OLDER UNITS - 300 MW RANGE AND REPRESENTATIVE FURNACE DESIGN.
- LARGER OPPOSED UNITS
- ONE WALL FIRED UNITS
- UNITS WHERE NO BASELINE IS POSSIBLE.

FIGURE 9

DESIGN PARAMETER COMPARISON
PRIMARY UNITS

	UNIT 1	UNIT 2	UNIT 3
STEAM FLOW (MLB/HR)	2300	2534	1450
S.H. TEMP (^{o}F)	1005	1005	1005
S.H. PRESS.	2610	2500	1990
FEEDWATER TEMP.	485	486	460
SEC. AIR (^{o}F)	541	600	647
TEMP. GAS LVG. BOILER (^{o}F)	655	690	750
TEMP. GAS LVG. AH (^{o}F)	291	266	270
UNIT EFF. (%)	88.88	84.57	85.23
FUEL, BTU/LB	11,500	8250	8624
ASH	16.0	5.2	4.87
H_2O	5.0	29.0	28.11
N_2	1.3	0.9	0.67
DRUM PRESS. (PSIG)	2770	2660	2115
HA/SC (KBTU/HRFT^2)	508.4	383.5	314.5

FIGURE 10

DESIGN PARAMETER COMPARISON

SECONDARY UNITS

	UNIT 5	UNIT 6	UNIT 7
STEAM FLOW (MLB/HR)	2,404	2,355	4,050
S.H. TEMP (^{O}F)	1,000	1,005	1,005
S.H. PRESS.(PSIG)	3,575	2,625	3,805
FEEDWATER TEMP.(^{O}F)	500	542	550
SEC. AIR (^{O}F)	603	565	589
TEMP. GAS LVG. BOILER (^{O}F)	646	635	628
TEMP GAS LVG. AH (^{O}F)	244	267	240
UNIT EFF. (%)	91.20	89.13	89.90
FUEL, BTU/LB	13,550	12,180	11,000
ASH %	8.5	11.6	12.48
H_2O %	4.0	5.2	5.2
N_2	1.3	1.2	1.0
DRUM PRESS. (PSIG)	NA	NA	NA
HA/SC (KBTU/HR FT^2)	600	460	690

FIGURE 11

DESIGN PARAMETER COMPARISON
ONE WALL-FIRED UNITS

	UNIT 1	UNIT 2	UNIT 3
STEAM FLOW (MLB/HR)	1,200	1,000	600
S.H. TEMP. (^{o}F)	1,005	1,003	1,005
S.H. PRESS. (PSIG)	1,875	1,825	1,990
FEEDWATER TEMP. (^{o}F)	470	485	463
SEC. AIR (^{o}F)	593	608	590
TEMP. GAS LVG. BOILER (^{o}F)	705	719	695
TEMP. GAS LVG. AH (^{o}F)	287	292	283
UNIT EFF. (%)	87.31	88.33	87.58
FUEL, BTU/LB	10,400	11,530	11,683
ASH %	12.2	13.0	9.31
H_2O %	13.0	8.5	6.90
N_2 %	0.97	1.4	1.21
DRUM PRESS. (PSIG)	2150	2,050	2,225
HA/SC (KBTU/HR FT^2)	254	235	290

FIGURE 12

NORTHERN STATES POWER
HIGHBRIDGE #12

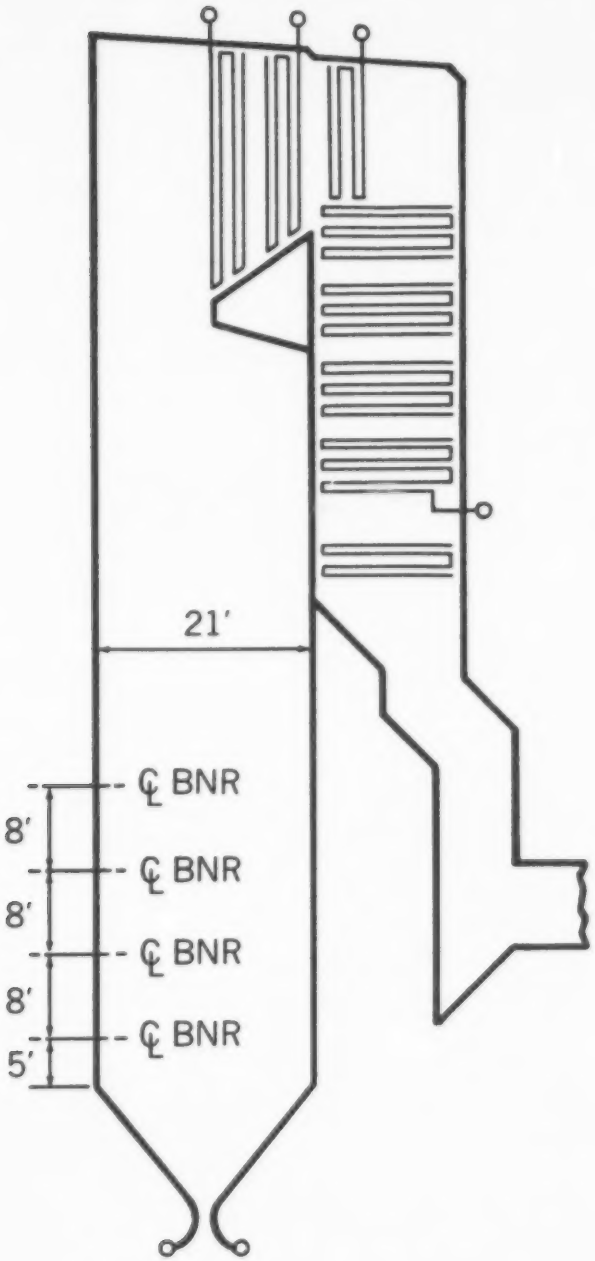


FIGURE 13

PRACTICAL REQUIREMENTS OF LOW NOx BURNERS

- SUITABLE FOR EXISTING ENVELOPE
- MINOR MODIFICATION TO HEAT FLUX PROFILE
- NO EFFECT ON THERMAL EFFICIENCY
- NO EFFECT ON UNIT PERFORMANCE
- NO INCREASE IN RELATED POLLUTANTS
- NO INCREASE IN LOWER FURNACE CORROSION POTENTIAL

FIGURE 14

LOW EMISSIONS BURNER DESIGN

A. ASSUMPTIONS

1. BURNER SIZE - NOMINAL 125 MKB/HR.
2. AREA INNER ANNULUS = AREA OUTER ANNULUS
3. THEORETICAL AIR = 7.57 LB/10 KB (AS FIRED)
4. SECONDARY AND TERTIARY AIR TEMPERATURE = 550°F
5. PRIMARY AIR TEMPERATURE = 150°F @ BURNER
6. WINDBOX PRESSURE = 4 INCHES W.C.
7. PRIMARY AIR PRESSURE = 5 INCHES W.C. @ BURNER
8. BAROMETRIC PRESSURE = 29.92 INCHES HG

B. DESIGN CRITERIA

1. DUAL AIR ZONE BURNER
2. TOTAL EXCESS AIR = 15%
3. STOICHIOMETRY
   - PRIMARY AIR - 0.2-0.25
   - BURNER - 0.7 TOTAL (INCLUDING PRIMARY AIR)
   - TERTIARY PORTS - 0.45
4. VELOCITIES
   - THROAT - 3600 FPM
   - PORTS - 3000 FPM (4 PORTS)
   - NOZZLE - 4500 FPM (3000 FPM MINIMUM)
5. THROAT (QUARL) HALF ANGLE - 25°

FIGURE 15

DISTRIBUTED MIXING BURNER
PRELIMINARY DESIGN

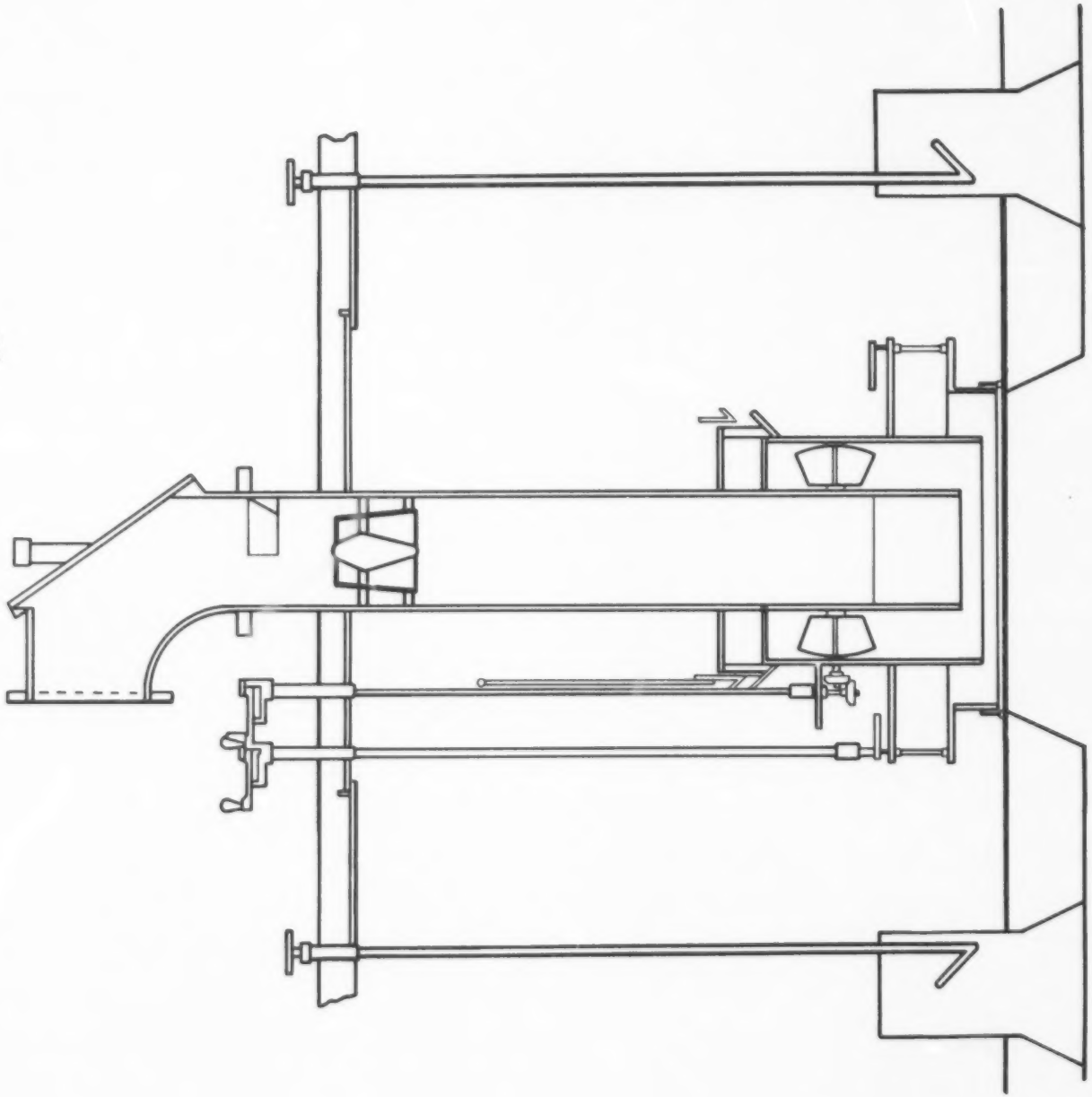


FIGURE 16

OPERATING EXPERIENCE AND FIELD DATA OF A 700 MW COAL-FIRED UTILITY BOILER WITH RETROFIT LOW NO_x STAGED MIXING BURNERS

By:

K. Leikert and S. Michelfelder
L. & C. Steinmueller GmbH
Postbox 1949/1960
D-5270 Gummersbach 1
West Germany

ABSTRACT

Forthcoming new federal regulations on emission control for stationary combustion systems will clearly define tolerable NO_x-emission levels in Germany and thus replace the present "best technical means" approach.

This fact gave reason to the initiation of a R&D program for the development of cost effective low NO_x-combustion equipment for use in pulverized coal fired boilers.

The program which was financially assisted by the Federal Ministry for Research and Development (Bundesministerium für Forschung und Technologie, BMFT) was subdivided into two parts:

As a first step a distributed mixing burner design concept adopted for an envisaged 50 % NO_x-reduction was tested and optimised in a pilot plant test program with a 2.5 MW burner. The burner design concept was based on a conventional circular burner with additional tertiary air nozzles distributed concentrically about the burner mouth. Within this program a 65 % NO_x reduction was achieved with an optimised configuration of the distributed mixing - respectively staged mixing burner (SM-burner) without disadvantageous changes in combustion and emission characteristics.

Following the successful pilot plant tests the combustion equipment of a 700 MW coal fired power station was changed to SM-burners. Both, to ease the retrofit and to safely allow the execution of a measuring program as retrofit burner a modified version of the optimized pilot burner design was used for the boiler. The modification resulted in a limitation of the safely operable tertiary air mass flows and thus to a certain extent reduced the staging capability of the large burner.

In spite of the narrower operational limits the envisaged goal of a 50 % NO_x reduction was met in the boiler demonstration tests. Furthermore a burner load dependent automatic secondary/tertiary air flow control system developed to guarantee a safe burner operation at low NO_x levels over a wide turn down ratio, was operated successfully.

Parametric studies, in flame and flue gas measurements were carried out to identify effects on NO_x-formation and potential problem areas at low NO_x-operation. Similarly to the pilot plant tests the staged mixing - dividing the flame into a fuel rich primary and a secondary burnout zone - proved to be the most effective single parameter on NO_x reduction. In the past 24 months of operation neither short term nor long term performance problems due to low NO_x operation could be detected.

SECTION 1

INTRODUCTION

Both federal government and local regulations on NO_x-emission from power station boilers in Germany force utilities and power station manufacturers to develop techniques which allow the operation of power station boilers in compliance with present and future regulations.

Unlike to flue gas desulphurization it has been shown by various international R&D programs that the most cost effective method to meet present and medium future NO_x legislation lies in the reduction of NO_x-formation by optimizing the combustion process, respectively the combustion equipment.

Numerous researches have clearly indicated that it has to be differentiated between basically two NO_x-formation mechanisms,

- the 'thermal NO_x' route, comprising all reactions which in their final result lead to the oxidation of originally molecular nitrogen, and

- the 'fuel NO_x' route, describing the oxidation of fuel bound nitrogen.

It is now well established that the thermal NO_x-formation predominantly depends upon the reaction temperature and the prevailing residence time at high temperatures, whereas the fuel NO_x-formation is more dependent on the oxygen concentration in the pyrolysis zone of the flame.

The relative importance of these individual reaction routes on the overall NO_x formation varies with the nitrogen content of the fuel. With natural gas firing due to the absence of fuel bound nitrogen only thermal NO_x can be formed, and thus the emission be minimized by controlling the time temperature history of the combustion products.

At residual fuel oil and pulverized coal firing the fuel NO_x formation mechanism often plays the dominant role. Experiments by Pershing et al (1) have shown that upto 80 % of the overall NO_x emission at coal firing was contributed by the fuel NO_x-formation mechanism.

As coal is or soon will be the only important fossil fuel for power generation in Germany it is evident that controlling NO_x emission from power stations will only be possible when the fuel NO_x formation mechanism can be controlled.

As stated above, this calls for an oxygen concentration control in the pyrolysis zone of the flame, which at the simultaneous requirement of short intense flames can be achieved by a staged respectively distributed mixing burner concept.

Using the Steinmüller circular burner configuration as basis, a novel distributing respectively staged mixing prototype burner (SM-burner) was designed which was subsequently further optimized and demonstrated in a two-phase program upon which is reported in this paper. A pilot test and optimization program with a 2.5 MW test burner was followed up by a largescale demonstration at a 700 MW power station which is equipped with 24 retrofit SM-burners.

Both program phases were carried out in cooperation with and financial assistance of the German Federal Ministry of Research and Development (Bundesministerium für Forschung und Technologie, BMFT).

SECTION 2

THE SM-BURNER CONCEPT

As Fig. 1 shows the SM-burner is derived from the reliable circular swirl burner. The pulverised coal is fed to the burner throat by an annular fuel gun and injected concentrically to the burner axis.

The former secondary air is now split up into two streams, a reduced secondary air flow which is passed as usual through the annular air duct surrounding the fuel gun, and a tertiary air flow to four tertiary air nozzles which are placed concentrically about the burner quarl exit.

At 100 % coal firing the core air butterfly valve is almost closed. It is adjusted in such a way that just sufficient core air is passed through the central duct to avoid recirculation flows induced by the swirling secondary air into the core air duct.

A variable swirl device allows a control of the secondary air swirl intensity.

The tertiary air quantity, respectively the tertiary/secondary air ratio , can be controlled by the butterfly valve in the tertiary air duct.

To control the overall burner stoichiometry, the total air flow to each burner is measured individually by a venturi type flow meter.

Fig. 2 shows a schematic of the anticipated flow and mixing regime of the SM-burner. As a result of the air supply chosen, the flame, which is stabilized within the burner mouth due to the prevailing aerodynamic conditions, is characterized by two distinct zones of different stoichiometry, a fuel-rich primary zone close to the burner exit, followed by an overstoichiometric secondary or burnout zone. The design concept thus enables to fulfil the low fuel NO_x-formation requirement of low oxygen concentration in the fuel pyrolysis zone of the flame and additionally, but to a lesser degree, reduces the thermal NO_x-formation as a consequence of lowering the maximum flame temperatures due to interstage cooling and increase of recirculation matter entrainment.

One of the main problems to be solved was to optimize the burner design and control in such a way to achieve optimum, low NO_x' conditions without substantial loss of combustion intensity, turndown potential and burnout performance.

The realization of simultaneous optimum, low NO_x-conditions, high combustion intensity and good burnout performance was achieved by an experimental optimization of

- shape, number and outlet area of staging air nozzles
- cross-sectional area of secondary air duct
- swirl intensity of secondary air flow
- fuel injection angle and velocity, and
- length of burner quarl.

As described in more detail in (2) a burner configuration could be derived from the pilot plant results for the 2.5 MW prototype burner which yielded the anticipated flow pattern (Fig. 3, type II flame) for a wide range of input conditions. At an overall burner stoichiometry of n_t = 1.25 a stable type II flame flow pattern was achieved at full load down to a 'staging ratio' of n_p = 0.55, 'staging ratio' n_p being defined as the stoichiometry of the primary zone (Fig. 2).

A further decrease of n_p caused a dramatic increase in flame length due to a change in flow pattern (Fig. 3, type I flame).

As long as the type II flow pattern is preserved ($n_p > 0.55$) staged mixing operation results in only moderate changes of flame length and combustion intensity. This fact is manifested by the axial decay of CO concentration on Fig. 4. Also plotted on Fig. 4 is the axial concentration of free oxygen with the staging ratio as parameter. The oxygen pattern proves the presence of a fuel-rich primary respectively pyrolysis zone close to the burner at $n_p < 1$.

The necessity to keep the fuel transport air quantity virtually constant independent of burner load in order to maintain the transportation characteristics does at decreased burner loads result in a reduction of the secondary air to primary air momentum ratio as long as the staging ratio n_p is kept constant. This momentum ratio, however, controls the flow pattern. At load reduction this causes the danger of a flame pattern change from type II to type I (Fig. 3).

To overcome this problem, an automatic load-dependent secondary/tertiary air distribution control procedure has been developed for the SM-burner, which was first tested during the demonstration of the 24 retrofit SM-burners at the 700 MW power station.

The load-dependent air flow control procedure is graphically illustrated on Fig. 5. Whereas the total air ($n = 1.25$) is reduced linearly with load, the secondary air flow follows the total air reduction only up to a certain load limit. At a further load decrease the secondary air flow is only degressively reduced which, of course, can be verified only at the expense of the tertiary air flow. As a consequence thereof the staging ratio is increased at reduced load in order to safely maintain the desired combustion characteristics at low load and yet to enable a maximal obtainable NO_x reduction at full load where the prevailing conditions allow safe operation at lower staging ratios.

SECTION 3

DEVELOPMENT DATA AND RETROFIT EXPERIENCE

The single burner pilot plant tests (2) had clearly indicated that at the conditions investigated the by far strongest individual effect on NO_x emission was caused by the staging ratio n_p. Fig. 6 exhibits the NO_x emission as a function of the staging ratio with the burner load as parameter. From this information it is also obvious that with respect to NO_x control the low load burner air flow control illustrated on Fig. 5 is tolerable, as load reductions result in considerably lower NO_x emissions anyhow.

The retrofit action was carried out at a 700 MW opposite wall fired single pass power station boiler with 24 burners. The boiler radiant section was subdivided by an evaporator-integrated division wall to minimize the slagging potential.

To reduce the retrofit costs and to minimize the operational risks it was decided to make use of the existing burners, thus adding only the tertiary air ports, the necessary ducting, flow control devices and instrumentation. Whereas this decision ensured that by only closing the valves of the tertiary air duct the original burner conditions could be restored at any time it limited the full exploitation of the SM-burner design for maximum NO_x reduction, as the optimum secondary air duct design could not be incorporated in the retrofit burner.

Results obtained from the power station after retrofitting the SM-burners are presented in two subsections. The data discussed and presented below refer always to flue gas measurements and simultaneous operation of 24 burners under same conditions, unless otherwise specified.

The demonstration tests as well as the pilot investigations were carried out with German SAAR coal of the following average composition:

Total water:	10	% by weight
Inherent moisture:	1.9	% by weight
Ash:	8.24	% by weight daf
Volatiles:	32.2	% by weight daf
Sulphur:	0.89	% by weight daf
Nitrogen:	1.1	% by weight daf
Net calorific value:	26.42	MJ/kg

Analyses taken over a longer period and illustrated on Fig. 7 show a considerable variation of the nitrogen content with time, which can of course affect NO_x emissions. The data for each individual parameter study have, however, been taken over a comparatively short time (several hours) so that a constant N-content can be assumed during the investigation of individual parameters.

PARAMETRIC EFFECTS ON NO_x EMISSIONS (700 MW BOILER)

Although the staging ratio in the retrofit burners was limited due to the above-mentioned design compromise, it proved to be again the most effective individual parameter. Fig. 8 shows a strong dependency of flue gas emission levels on the staging ratio. The overall excess air level, characterized by the various symbols on Fig. 8, has only a negligible influence.

Furnace respectively burner loading has also a substantial effect on NO_x emission, as is illustrated on Fig. 9. This fact is important as it more than equalizes the effect of the limited staging ratio at low load burner operation due to the automatic air flow control (Fig. 5).

Whereas some authors have reported an effect of combustion air swirl intensity on NO_x formation, this investigation revealed, neither at unstaged nor at staged operation, an influence of secondary air swirl intensity on NO_x emission (Fig. 10, $n_p = 0.9$).

Heap and Pershing (3) measured a pronounced increase in NO_x formation with decreasing particle size distribution in a one-dimensional flow reactor at unstaged condition. A change of the coal fineness during this demonstration test from nominal 35 % > 90 % µm to 29 % > 90 µm indicated an opposite trend (Fig. 11). The likely reason for this discrepancy lies in the different flow and mixing regimes. An increase of fineness in the one-dimensional flow reactor results at unstaged conditions in the first place in a better mixing between fuel and oxidant and thus also increases the probability that nitrogen species are oxidized immediately after devolatilization. Under staged conditions with the SM-burner a decrease in particle size distribution also leads to a better mixing resulting in a faster reaction, however with the important difference that at the overall fuel rich equivalence ratio in the primary zone this rather leads to an increase in oxygen deficiency than to an increase in nitrogen species oxidation.

IN-FLAME MEASUREMENTS AND OPERATIONAL EXPERIENCE (700 MW BOILER)

Flame Measurements

Measurements within the radiant chamber of the boiler have been carried out to identify any significant changes due to the staged mixing operation. Visual observations did not show any important changes.

Temperature measurements carried out with a radiation pyrometer (Pyropto) illustrate the relativechanges in ignition zone (primary zone) temperature and the overall axial temperature distribution (Fig. 12). It can be seen that the primary zone temperature, respectively radiation intensity, drops when the burner is operated in the distributed mixing mode, whereas the axial temperature pattern exhibits a slight increase. Inspite of these changes the heat absorption characteristics of both radiant section and superheater remained, however, unchanged. A further reduction of the slagging tendency at the burner level cross-sections of the boiler, observed when the burners were operated

in the distributed mixing mode, may be attributed to the temperature reduction in the primary zone.

Another important question which could be clarified partially by measurements within the furnace atmosphere is if corrosion processes at the outer tube surfaces would be stimulated or accelerated due to the distributed mixing burner operation. As potential danger an increased CO-content, with its detrimental effect on CO-corrosion mechanisms, was identified. To investigate these potential problems, two measurements have been performed:

- CO-concentration measurements in the furnace chamber
- tube wall thickness measurements before the retrofit action and again after 24 months of boiler operation with staged mixing burners.

The 2nd series of tube wall thickness measurements have not yet been carried out, but results should be available at the time this paper is being presented.

Gas concentration measurements in the external recirculation matter, which are illustrated on Fig. 13 however, do not indicate any increase in CO-corrosion danger. Inspite of the inspected CO concentration increase towards the burner axis, staged mixing operation does not lead to an increase of CO at the furnace wall areas.

Long-Term Flue Gas Data

At no time any change in flue gas CO emissions was observed, the retrofit of SM-burners thus had no detrimental effect on the CO emission characteristics.

Long-term measurements of uncombusted carbonaceous matter in the fly ash did exhibit a moderate but distinct increase (Fig. 14). Before the retrofit of the SM-burners, ash analyses revealed a 2-3 % content of combustible matter in the fly ash. After the retrofit of SM-burners, the carbonaceous matter in the fly ash increased to a maximum of 4-6 %. This tendency seemed to present basic problems in as much as it results in an efficiency loss and, furthermore, leads to potential problems in the use and sale of fly ash to cement works who limit the content of carbonaceous matter in fly ash for their use generally to 5 %.

A crosscheck with fly ash obtained from an unstaged operation, which was possible due to the retrofit burner compromise (reuse of old burner with controllable tertiary air streams), gave however no change in fly ash composition. This indicated that the fly ash problem had to be attributed mainly to another cause which was found in the mill system. The mills had run more than 15 000 hours without any change of wear parts, resulting in an increase in particle size distribution up to 42 % > 90 µm.

After an appropriate adjustment of the classifiers the unburnt matter in fly ash could again be reduced to an average of 3.5 %, as shown for the 2nd half of 1979 in Fig. 14.

Additionally to the problem of unburnt matter in fly ash, it was of interest if and to what extent the collection efficiency (respectively the fly ash properties) of the electrostatic precipitator would be effected by the distributed mixing mode operation of the SM-burners. Neither precipitator efficiency and total solids emission measurements nor electron microscopic evaluations of ash samples revealed any influence of staged mixing. The latter results are to some extent contradictory to preliminary results from Martin (4) who reported that retrofitting low NO_x coal burners to a boiler in the U.S. had resulted in a distinct increase of fine particulate formation.

Finally, long-term NO_x emission data are plotted on Fig. 15, which are representative for today's continuous boiler operation with the adopted automatic combustion air control illustrated on Fig. 5. Whereas the triangles on Fig. 15 are points from a measuring series which has been taken to assess the dependency of NO_x emission on burner load for the adopted air flow control, the circular points represent data which have been collected over a 10-week period in March/April 1979 and two weeks in February 1980. In spite of the considerable scatter of ± 40 ppm, which may be attributable to irregularities in the coal composition, all values were below the 1979 EPA NSPS.

SECTION 4

SUMMARY - CONCLUSIONS

The paper reports on a development and design optimization programme for a distributed mixing burner and on retrofit experience from a 700 MW opposed wall single pass boiler. Notable results can be summarized as follows:

1) The staged mixing, respectively distributed mixing principle, was proven to be an effective tool for the reduction of NO_x emission from coal-fired power station boilers. The achieved reduction of more than 50 % is predominantly attributable to the suppression of fuel NO_x formation.

2) The SM-burner concept realizes the NO_x reduction without significant changes in combustion intensity and flame shape nor loss in turndown capacity.

3) It can be expected from the pilot experiments that a full size SM-burner design based upon the optimized pilot burner configuration - without compromise as accepted for the retrofit burner - will result in a further increase in NO_x reduction efficiency to approximately 70 %.

4) The slagging tendency in the radiant section reduced when the SM-burner was operated in the distributed mixing mode. No disadvantageous effects on operational safety and CO corrosion potential were detectable up to now. Tube wall thickness measurements which will be carried out shortly after a 24-month operation cycle shall allow final conclusions on this point.

5) Neither a change in fly ash properties and particle size distribution nor an increase in CO emission have been found at distributed mixing operation.

6) A slight increase in uncombusted carbonaceous matter in the fly ash has been detected. The absolute values of approximately 3.5 %, however, lie within the tolerable limits. This increase in carbonaceous matter in the fly ash is noted here as a potential disadvantage although a crosscheck with non-staged mixing operation indicated that it has to be rather attributed to a change in coal quality than to the distributed mixing concept.

7) Until now the operational experience is limited to one coal and one boiler only. Before a final generalization of the reported results and experience is possible more information is required. The effect of coal type will be investigated by further tests in the 2nd half of 1980 as part of a joint program between EPA, BMFT and Steinmüller.

   These tests will be carried out atEnergy & Environmental Research Corporation, Santa Anna in California. Further experience will be gained from two new 600 MW boilers presently under construction in Germany.

8) Once the information to be generated from the additional tests and the new boilers is available it can be hoped that with the SM-burner concept a cost effective low NO_x technology is available for both new and via retrofit also existing installations.

SECTION 5

REFERENCES

(1) Pershing, D.W., Brown, J.W., Martin, G.B. and Berkau, E.E.: Influence of design variables on the production of thermal and fuel NO from residual oil and coal combustion. Presented at 66th Annual AIChE Meeting, Philadelphia, Nov. 1973.

(2) Michelfelder, S., Leikert, K.
Development program and operating experience with pulverised coal staged combustion burners for steam boilers.
American Flame Research Committee,
Oct., 22-23, 1979, Houston, Texas

(3) Heap, M.P., Pershing, D., EER- SANTA ANNA
Private communication on experimental data obtained in bench scale tests
Sept. 1978

(4) Martin, B., EPA - RTP
Private Communication

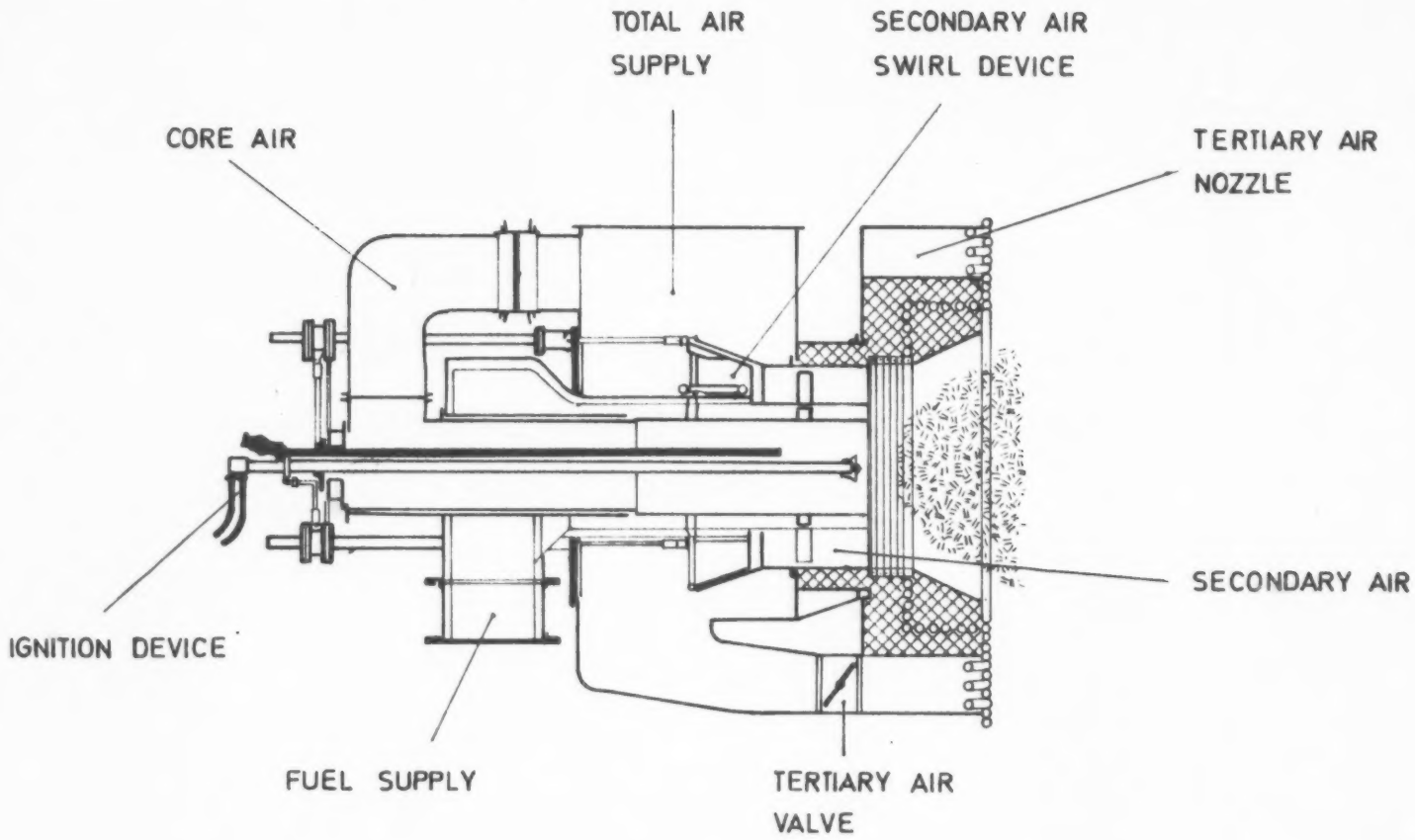


Figure 1. Staged Mixing Burner (SM-Burner).

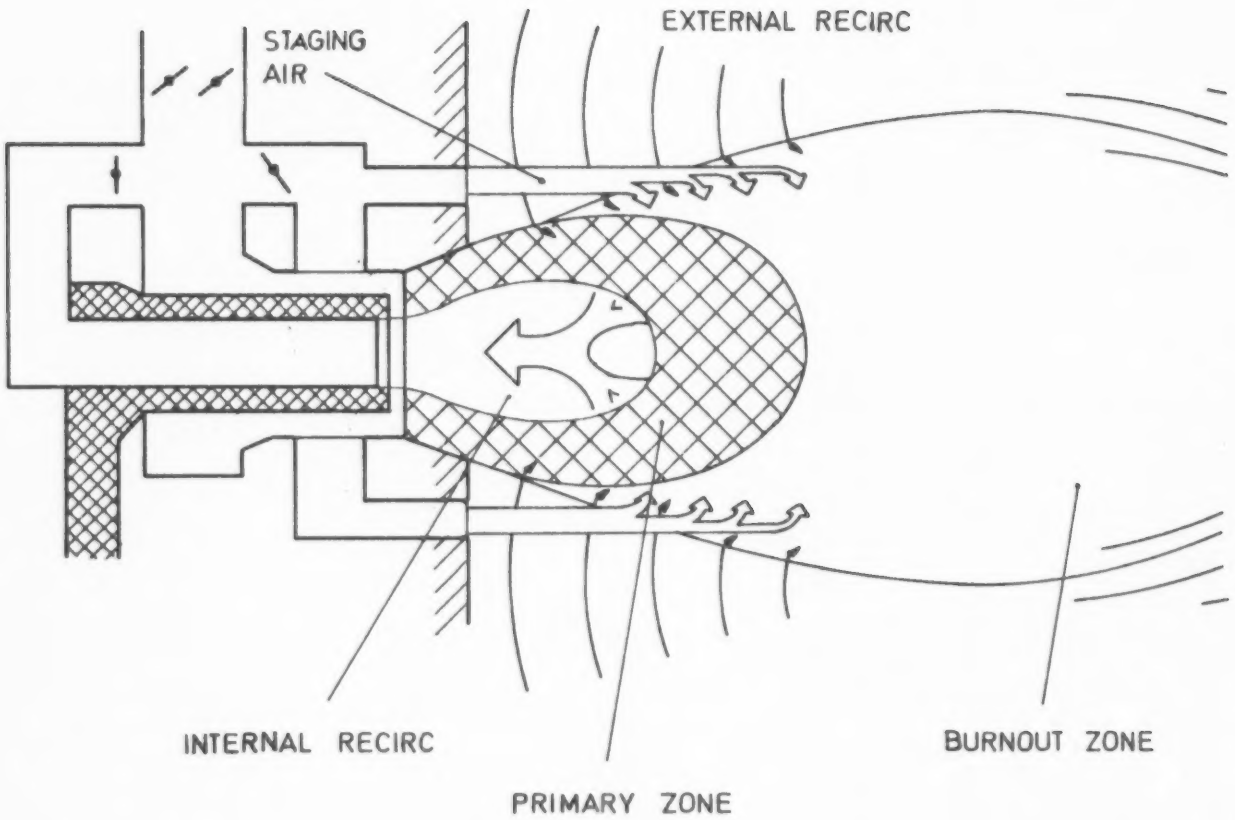


Figure 2. SM-Burner, Schematic of Flow and Mixing Regime.

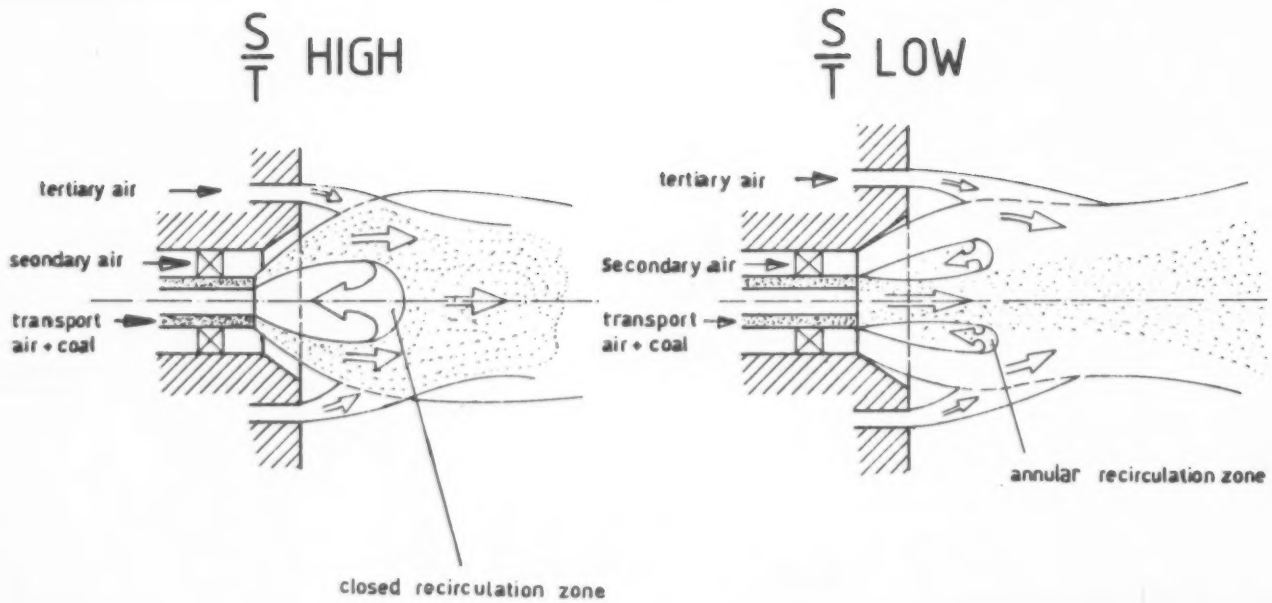


Figure 3. SM-Burner, Flowpattern Depending on Secondary Air/Transport Air (S/T) Ratio.

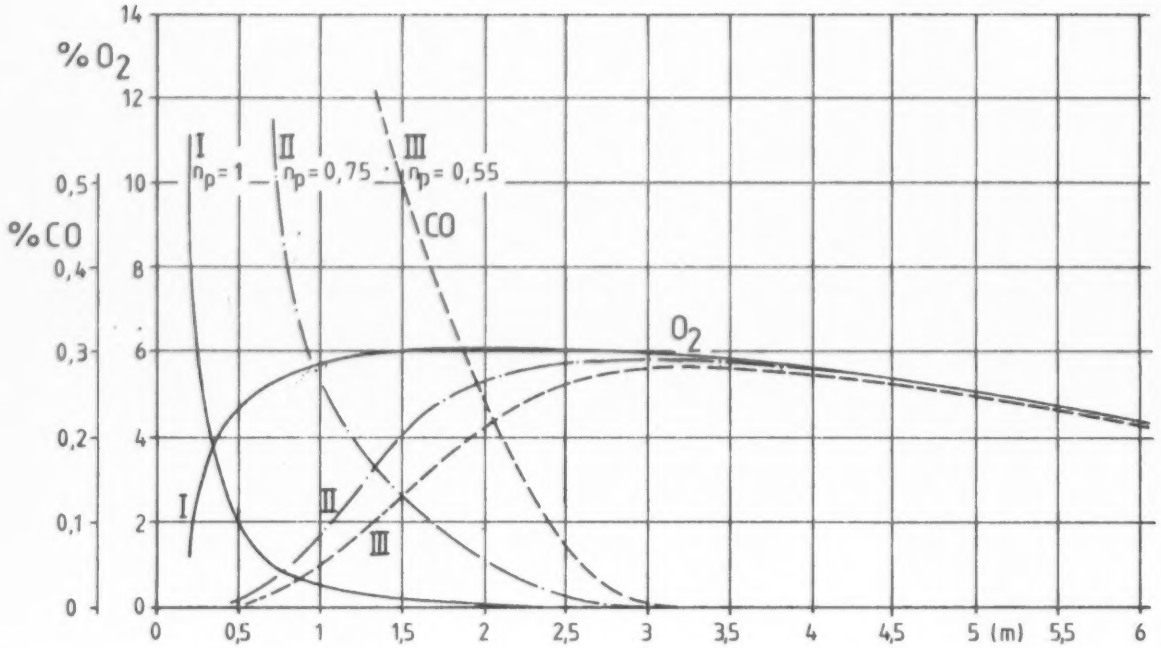


Figure 4. Axial CO and O_2 Concentration Profiles as Function of Primary Zone Stoichiometry (np).

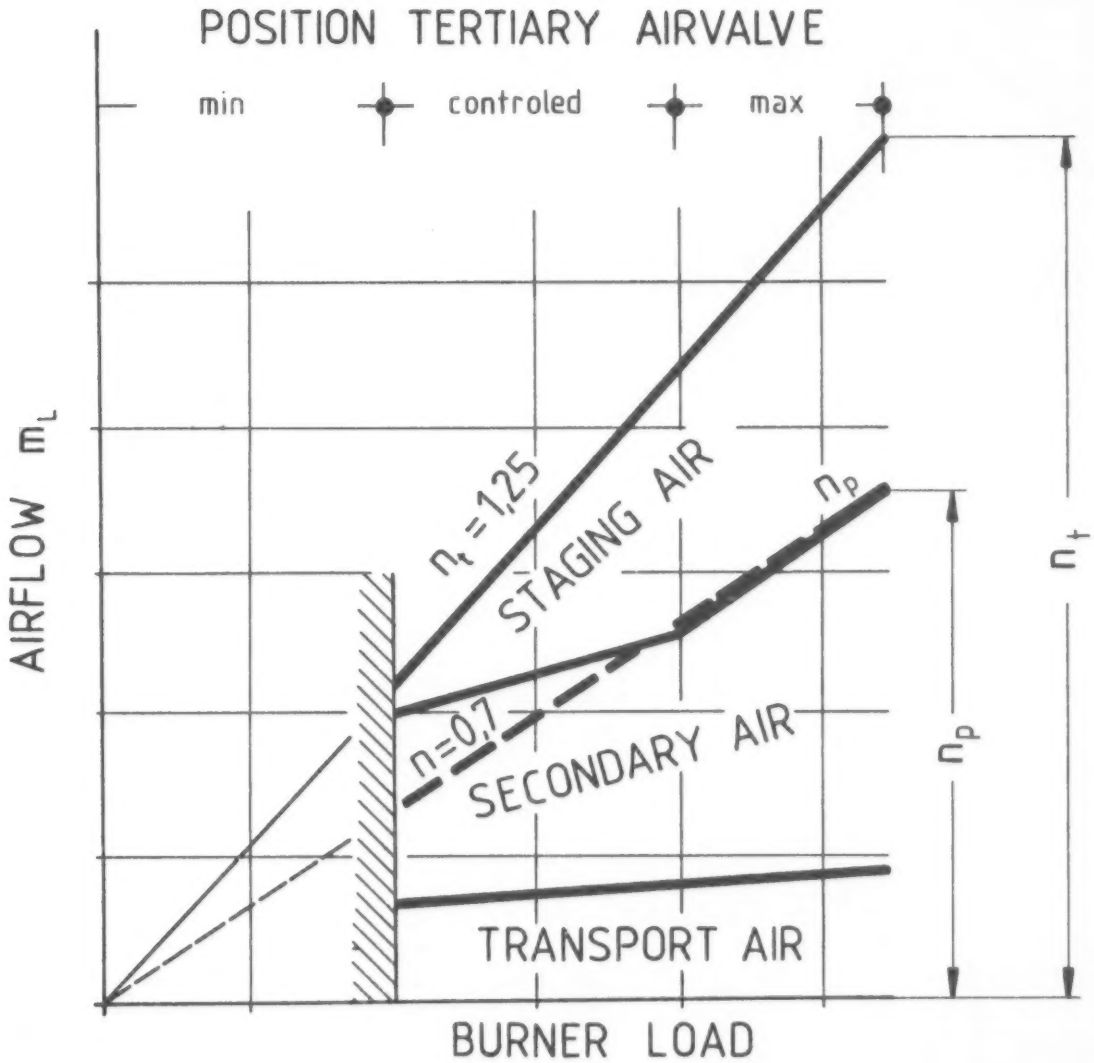


Figure 5. Air Flow Distribution as Function of Burner Load (Control Procedure).

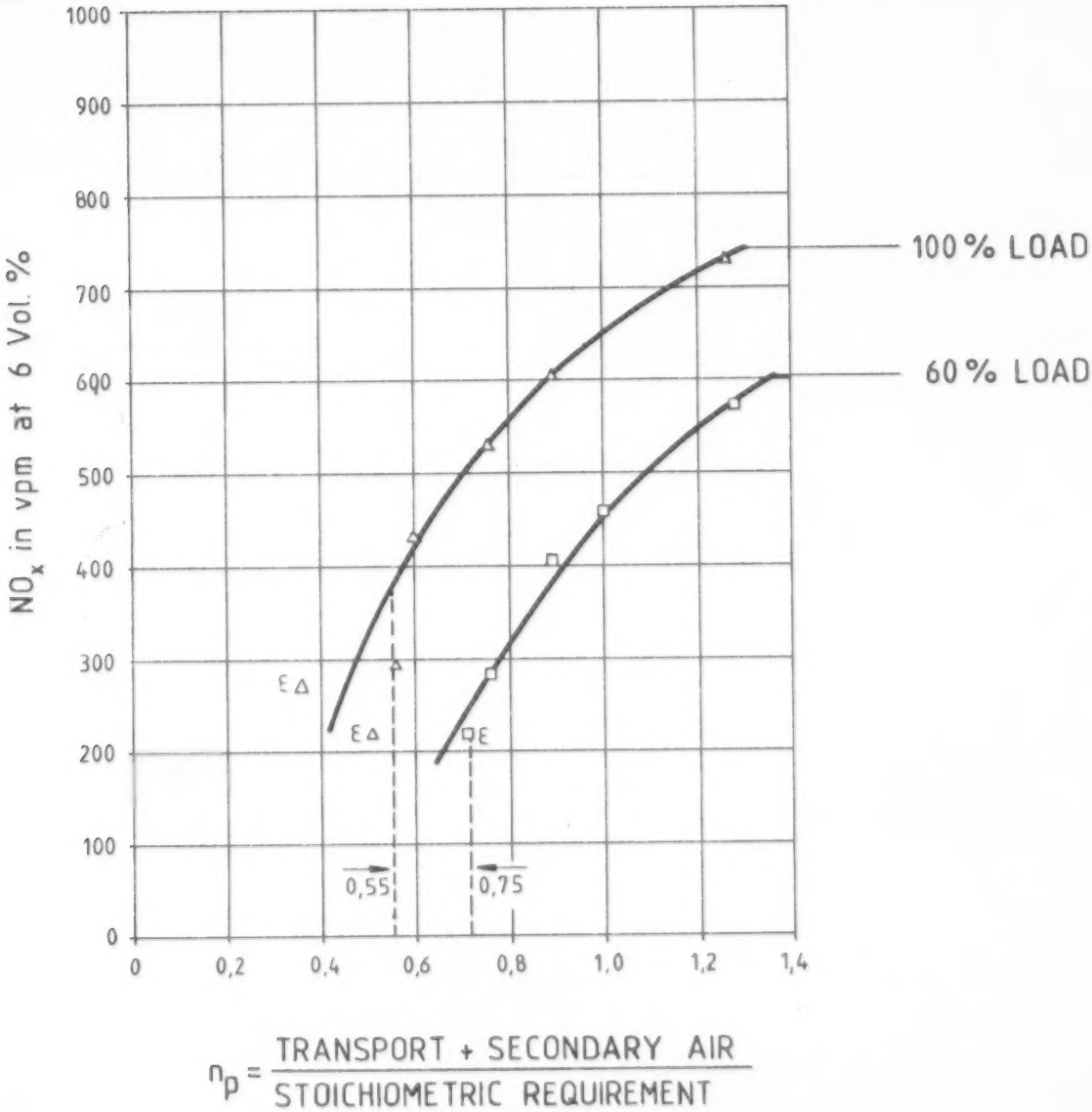


Figure 6. Optimized Pilot Burner, NO-Emission as Function of Primary Zone Stoichiometry (np).

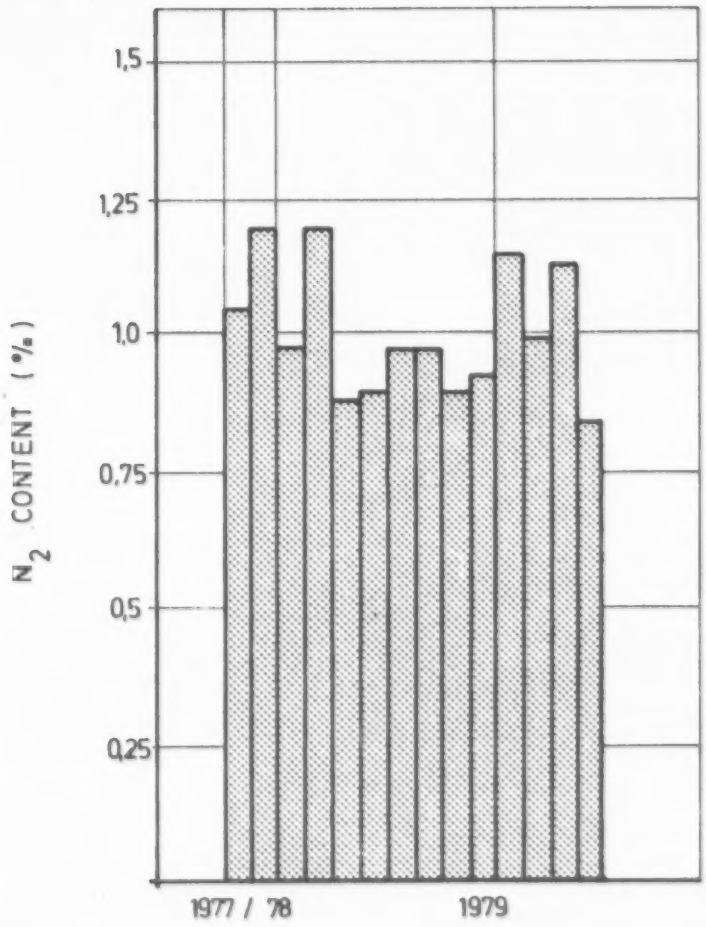
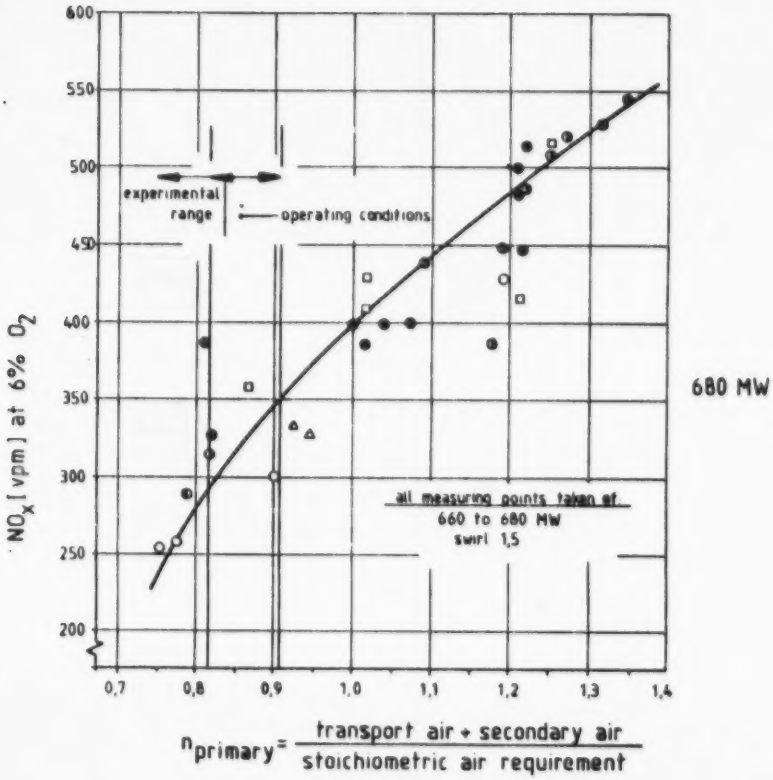


Figure 7. Variation of Coal Nitrogen Content with Time.



O_2-content of flue gas (Vol%)	4-4,5	4,5-5	5-5,5	5,5-6	6-7	7-9
symbols	○	◐	◑	●	□	△

Figure 8. Retrofit Burner, NO_x Emission as Function of Primary Zone Stoichiometry (np).

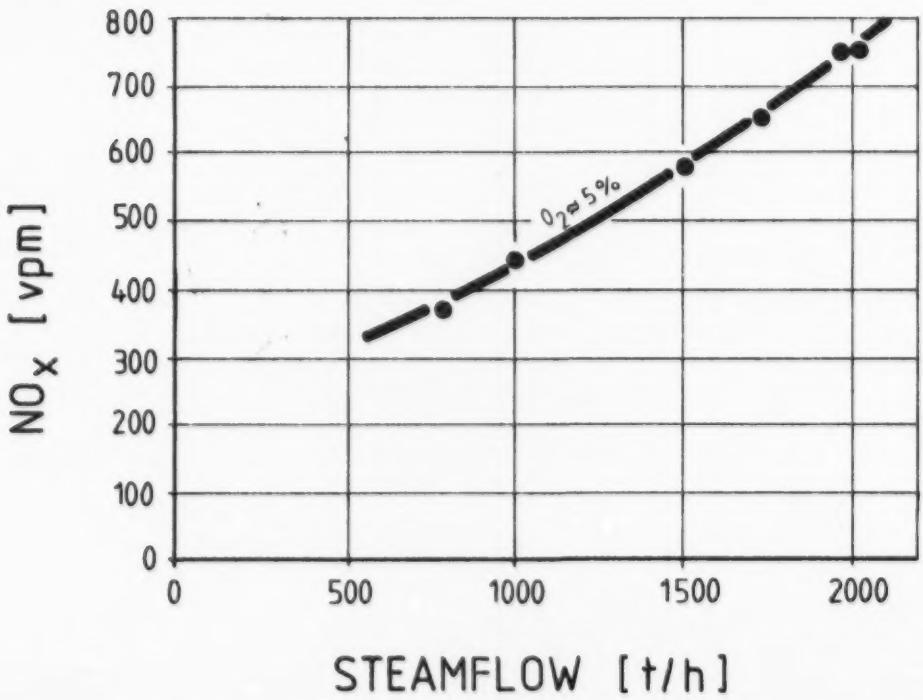


Figure 9. NO_x - Emission as Function of Boiler Load (Unstaged).

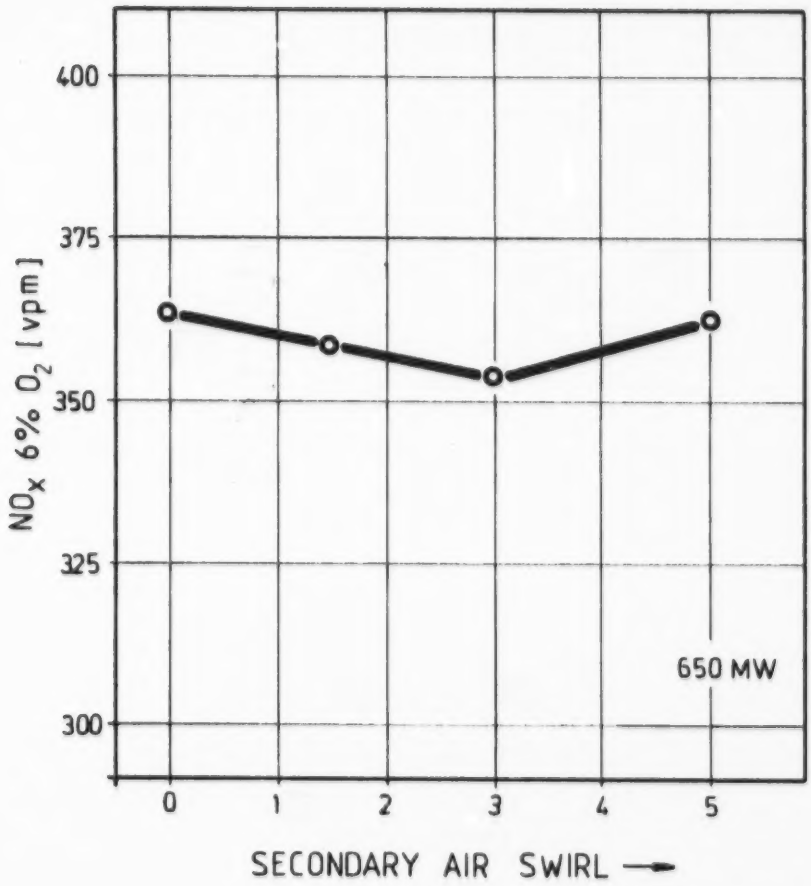


Figure 10. Retrofit Burner, Effect of Swirl on NO_x Emission.

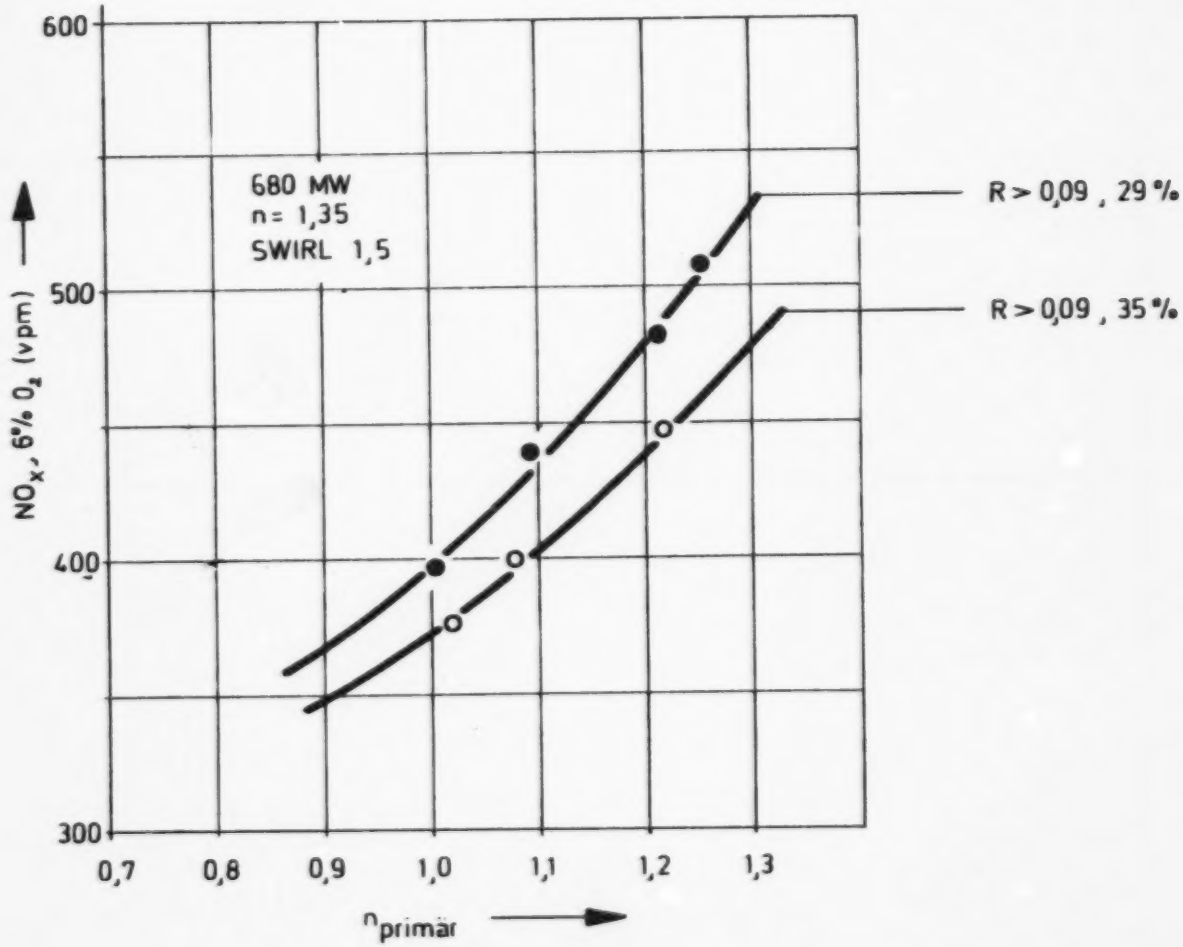


Figure 11. Retrofit Burner, Effect of Coal Fineness on NO_x Emission.

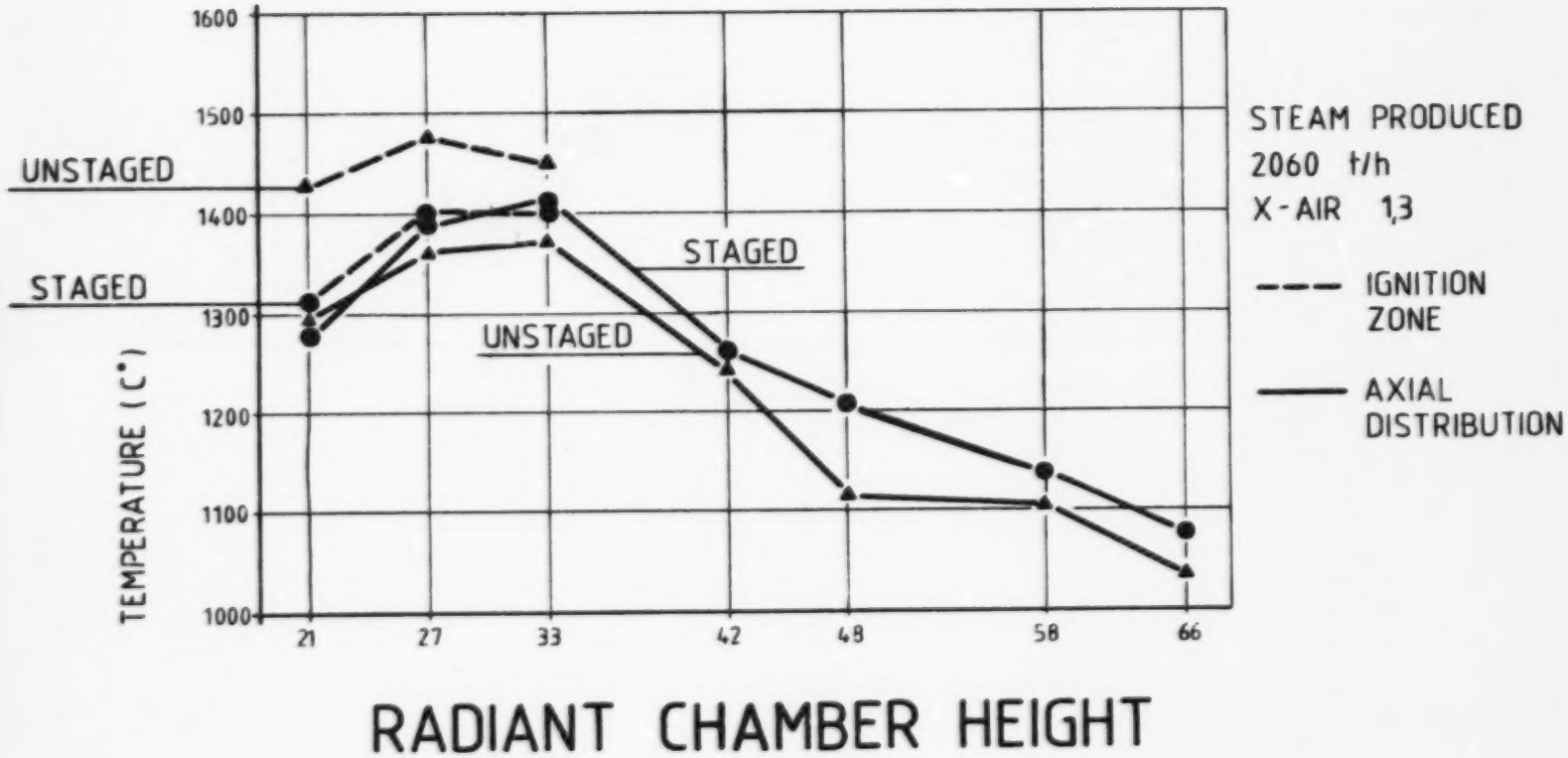


Figure 12. Retrofit Burner, Ignition Zone and Axial Temperature Distribution.

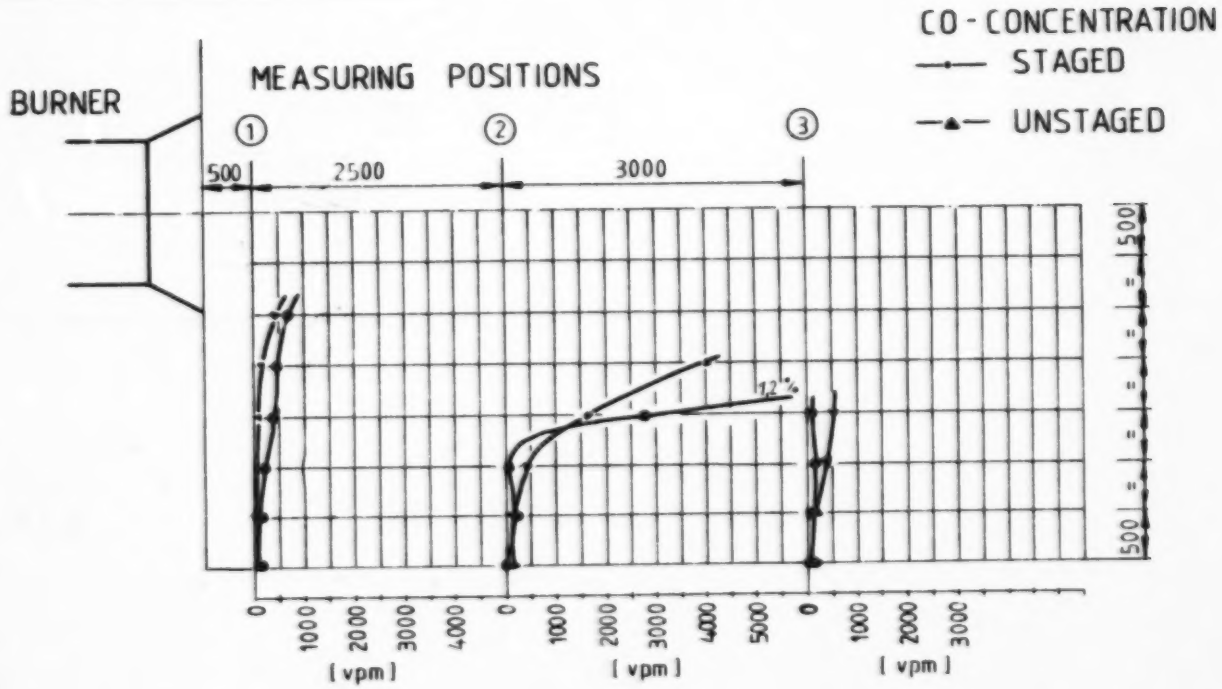


Figure 13. Retrofit Burner, In-Flame CO - Concentration Measurements.

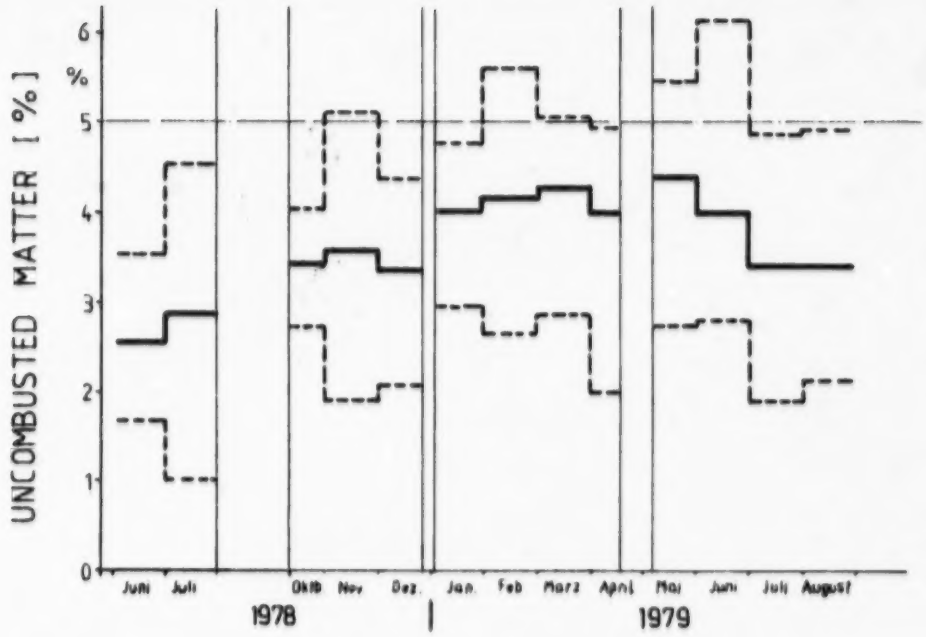


Figure 14. Uncombusted Carbonaceous Matter in Fly Ash, Variation with Time.

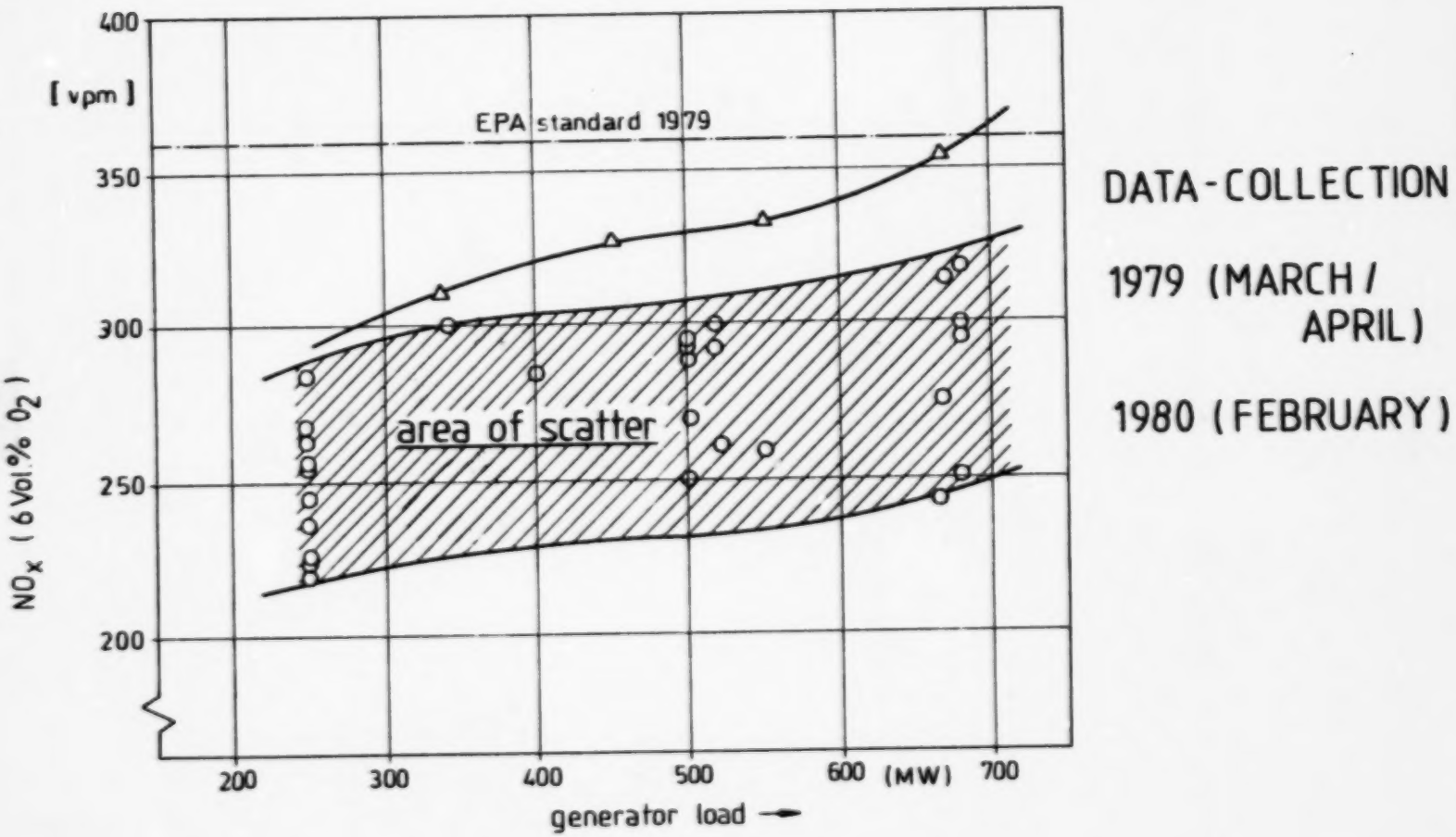


Figure 15. Retrofit Burner, Long Term Fluegas NO_x Data as Function of Boiler Load.

JAPANESE TECHNICAL DEVELOPMENT FOR COMBUSTION NO_x CONTROL

By:

K. Mouri and Y. Nakabayashi
Electric Power Development Company, Ltd.
8-2, Marunouchi 1 chome, Chiyoda-ku,
Tokyo 100 Japan

ABSTRACT

Electric Power Development Co., Ltd. has been executing a research and development program on combustion NO_x control for coal-fired boilers in cooperation with Japanese boiler manufacturers. Target NO_x emission levels of 100 ppm or below (O_2 = 6%, N = 1.8%) have been defined and to date have not been achieved.

However, results obtained from this program have been applied in a stepwise manner to existing or new coal-fired power plants. NO_x emission levels for existing plants have been reduced to 160 - 300 ppm (O_2 = 6%, N = 1.2%) in comparison to uncontrolled levels of 400 - 500 ppm. Regarding new coal-fired boilers, EPDC is constructing two 250-MW boilers with target emission levels of 250 ppm (O = 6%, N = 1.7%) at the Matsushima Thermal Power Station. In addition, plans are to construct a 700 MW boiler at Takehara (No. 3 unit) with target emission levels of 200 ppm. Presently, EPDC believes that NO_x emission levels will be 150 ppm (O_2 = 6%, N = 1.8% design base) for the No. 3 unit boiler.

This report describes ongoing R&D programs, and the results of combustion modification efforts (such as the technology development of low NO_x burners, two-stage combustion, gas mixing, etc.), and low NO_x countermeasures for new boilers.

ACKNOWLEDGEMENTS

We sincerely appreciate the joint researchers of EPDC for assistance in writing this paper.

Section 1

INTRODUCTION

As coal use is expanded, environmental issues become more important. In general, most of the environmental risks associated with coal combustion are amenable to control.

These environmental impacts differ because of regional characteristics such as meteorology, population density and resource distribution. Thus, it is not surprising that nations and regions take different approaches to environmental control measures.

Japanese government environmental standards are the most stringent in the world. Local governments may impose standards on pollutant sources which are more stringent than required by national law. Almost all local governments have independently enacted pollution control ordinances. Thus, power utilities in Japan must take countermeasures to meet the stringent standards and pollution control ordinances of local governments.

NO_x emission levels of coal-fired boilers are remarkably high in comparison to the other fossil fuel-fired boilers. Development of NO_x control technologies for coal to meet emission levels achievable for LNG or oil combustion is very difficult.

Electric Power Development Co., Ltd. (EPDC) has been developing NO_x control and removal technologies in cooperation with Japanese boiler manufacturers. Two methods to reduce NO_x emissions from boilers have been pursued. The first is postcombustion NO_x removal, such as Selective Catalyst Reduction (SCR) and Selective Non-Catalytic Reduction (SNR). The second method focuses on combustion NO_x control such as low NO_x burners and combustion modification.

EPDC and Japanese manufacturers have been has been conducting R&D programs on both methods. This paper describes the results of the combustion NO_x control program, while the results of using postcombustion methods are reported in another paper at this Symposium and for convenience summarized in Appendix A.

Section 2

NO_x CONTROL REGULATIONS IN JAPAN

STATUS OF AMBIENT NO_x LEVELS

In August 1967, the Basic Law for Environmental Pollution Control was enacted for the purposes of protection of national health and the preservation of the of living environment.

The Japanese government selected the environmental quality standards in May of 1973 and revised them in July of 1978. These environmental quality standards are shown in Table I. The revised standards are slightly less stringent than the initial standards.

After the revised standards were enacted, regional noncompliance areas (over 0.06 ppm) consisted of 4.6% of all general environmental-atmosphere stations (892 sites) and 36% automobile influenced stations (182 sites). The current compliance status with the NO_x environmental quality standard is shown in Figure 1. Figure 2 shows that the emissions NO_x density increased from 1971 to 1973, but has remained approximately constant since then.

NO_x EMISSION REGULATIONS

NO_x emission regulations for stationary sources were established in August 1973, and revised four times prior to the present environmental quality standard. Table II shows the progressive changes in the NO_x emission standards to the current levels of 400 ppm (at 6% O_2) for coal-fired boilers and 150 ppm for oil-fired boilers (at 4% O_2).

POLLUTION CONTROL ORDINANCES OF LOCAL GOVERNMENTS

Pollution control ordinances imposed by local governments are generally more stringent than the national standards. Examples of local ordinances imposed on existing coal-fired plants are shown in Table III. Local ordinances applicable to new coal-fired plants are shown in Table IV.

Matsushima City is located in Nagasaki Prefecture of western Japan. Here NO_x emission controls are less stringent than elsewhere since the area is not heavily industrialized. Thus, the Matsushima thermal power station does not employ SCR technology.

However, at Takehara thermal power plant where the No. 3 unit is currently under construction, another power company is planning to construct a large thermal power plant nearby. In this instance, the local government has requested the power companies not to increase total NO_x emissions beyond present levels. Thus emissions from Takehara Unit No. 3 and the new power station must comply with the stringent controls shown in Tables IV and V. This situation has required EPDC to install both SCR equipment and combustion NO_x control technology on Takehara Unit No. 3.

TOTAL MASS NO_x CONTROL

Six industrial areas in Japan (e.g., Tokyo and Yokohama) do not now meet the established NO_x ambient air quality standard of 0.04 ppm. Local governments in these areas are considering stringent NO_x controls to achieve this standard.

In August 1977, the city of Yokohama (the leading local government for pollution control), proposed an NO_x Guidance Plan that would reduce NO_x emission levels 36% by 1981 from major industries. Since EPDC's Isogo thermal power station is located in Yokohama, a 36% NO_x reduction may be required. The NO_x Guidance Plan stipulated that the time limit to retrofit combustion controls extended until April 30, 1979. If SCR was used, this time limit extended to March 31, 1981.

EPDC has elected to apply combustion modification because the Isogo Power Station is too narrow to install the SCR equipment. The combustion modifications chosen are described in this paper.

Section 3

OBJECTIVES OF COMBUSTION CONTROL DEVELOPMENT FOR COAL-FIRED BOILERS

EPDC has two objectives in NO_x combustion control develoment. The first objective is to develop a technology that will meet existing NO_x control regulations. The second is to reduce cost of control compared to SCR.

NO_x emission levels from the combustion of oil or LNG are low in comparison to coal-fired boilers. If advanced combustion control technologies were applied to oil or LNG boilers, NO_x emissions would be less than 100 ppm for oil and 50 ppm for LNG.

Reductions to these levels may not justify the installation of SCR equipment for oil and LNG boilers in most areas of Japan. To date, however, the Shinkokura power plant and other oil-fired plants in Japan have installed SCR equipment.

For coal, advanced NO_x control technology would enable stack gas NO_x levels to be reduced to only 200 ppm (O_2 = 6%) because of the inherent high nitrogen content of the fuel (Table VI). In Japan, environmental preservation takes precedence over other factors such as the economy and the desire to reduce oil and gas consumption. Thus, local governments and the public have demanded lower NO_x levels in order to approve new facilities. These actions have forced NO_x emission levels for coal-fired boilers to comparable levels for oil-fired units. In most cases, this requires the application of SCR equipment. However, EPDC is also developing combustion NO_x control technology to obtain the most economical and lowest emission coal-fired power plant through a combination of combustion and SCR control technology.

EPDC'S TARGET OF COMBUSTION NO_x CONTROL TECHNOLOGY

EPDC's target emission level obtainable with combustion NO_x control technology is 100 ppm (and below) at 6% O_2 and 1.8% fuel nitrogen content. Figure 3 shows three cases of a model low pollution coal-fired thermal power plant.

Case 1 is Takehara No. 3 unit, which is under construction. Takehara No. 3 will have SCR equipment and be capable of NO_x emission levels of 60 ppm and below.

Case 3 employs a Dry FGD system, which does not have SCR equipment, but the NO_x emission level is aimed at 60 ppm and below. This is due to capture of NO_x within the FGD system to the degree that an inlet NO_x concentration of 100 ppm will be reduced to 60 ppm at the FGD exit. Case 3 has been determined to be the most economical, reliable, and least polluting coal-fired plant in EPDC's analyses.

Section 4

EPDC COMBUSTION NO_x CONTROL DEVELOPMENT PROGRAMS

Since 1977, EPDC has been conducting R&D programs for low NO_x emission coal-fired boilers in joint research with Japanese boiler manufacturers, such as Mitsubishi Heavy Industries (NHI), Babcock Hitachi K.K. (BHK), Ishikawajima Harim Heavy Industries (IHI) and Kawasaki Heavy Industries (KHI).

This R&D, using test furnaces owned by boiler manufacturers is testing various types of imported coals (from Australia and China among others) planned for use in new coal-fired power stations. The range of nitrogen content for coal stocks from these countries is shown in Table VI.

An outline of EPDC's R&D program for combustion NO_x control technology is shown in Table VII.

Testing is being performed as follows:

- Survey tests to achieve lower NO_x emissions by optimizing conditions of two stage combustion, gas mixing, etc., and

- Confirmation that CO, unburned hydrocarbons, unburned carbon and the other pollutants do not increase.

Recently, our joint researchers built a multi-burner test furnace. We anticipate obtaining good data concerning the interacting effects between burners.

Section 5

R&D RESULTS OF TEST FURNACES

NO_x REDUCTION LEVEL

One sample of test results is shown in Figure 4. Test conditions are for 1.7% and 0.9% nitrogen content in coal and for (1) a conventional burner, (2) a new low NO_x burner without Two Stage Combustion (TSC) or Gas Recirculation (GR), (3) a new low NO_x burner with TSC but without GR and (4) a new low NO_x burner with both TSC and GR.

Under the best conditions, NO_x emission levels are between 160 ppm and 210 ppm, (unburned carbon content below 5%) for 1.7% N, and between 90 ppm and 150 ppm for 0.9% N.

An outline of the results for the test furnaces is as follows:

- The new burner improves NO_x levels by roughly 40 ppm to 60 ppm.
- TSC improves NO_x level 60 ppm to 100 ppm.
- TSC combined with GR improves NO_x levels by 80 ppm to 100 ppm.
- Higher fuel nitrogen content increases NO_x emissions.
- Total NO_x reduction is 270 ppm to 280 ppm from the levels emitted by a conventional burner.

EPDC and its joint researchers will investigate more effective combustion conditions and further advanced low NO_x burners to achieve the target 100 ppm NO_x emission level.

P.O.M. MEASUREMENT RESULTS

Table VIII shows P.O.M. measurement results at one particular test furnace.

This measurement was performed using the EPA No. 5 modified sampling method developed by Battelle and a liquid chromatography analyzer.

These measurements indicate the following:

(1) Total emissions of P.O.M. with two stage combustion (reported in the United States as an increase of 35%) increased 32%.

(2) The increase of P.O.M. emission owing to combustion modification is 20 to 60%.

(3) Absolute P.O.M. values increase at partial load.

(4) Measured P.O.M. emissions were much less than the values reported in the U.S.A. It is not clear whether the observed difference is due to the measuring method (GC-MS method in the U.S.) or the type of coal. This difference shall be studied in the future.

Another observation is that as NO_x emissions decrease with combustion modification, P.O.M. emissions increase. Therefore, some adjustment is needed to alleviate this problem.

This correlation is shown in Figure 5, and according to the data taken by Hitachi, P.O.M. emissions are around 10 $\mu g/Nm^3$ when NO_x emissions are lowered to 100 ppm. This is about five times that of normal combustion.

Section 6

COMBUSTION MODIFICATION EXPERIENCE AT ISOGO THERMAL POWER STATION

The Isogo power station is located in city of Yokohama about 30 km south of Tokyo in an area known as the Keihin Industrial Area. The City of Yokohama is very anxious to reduce pollution, and thus the pollution prevention agreement between Yokohama city and EPDC is uniquely severe.

In 1977, Yokohama city proposed a guiding principle for restricting NO_x emissions, resulting in a NO_x emissions reduction of about 3[illegible]. Accordingly, the proposed NO_x emission level from a coal-fired plant in Yokohama is 159 ppm.

HISTORY

Isogo No. 1 and No. 2 boilers (capacity of 265 MW each), manufactured by Ishikawajima-Harima Heavy Industries Co., Ltd. (IHI), were completed in 1967 and 1969, respectively. A summary description and general boiler arrangement are shown in Table IX. The original burner arrangement is shown in Figure 6.

In advance of the first restrictive regulations on NO_x emissions from stationary sources in 1973, Isogo Units 1 and 2 were equipped with two stage combustion with an over air port system (OAP) for NO_x control.

As a second step and in accordance with successive, more stringent regulations, IHI-FW dual flow pulverized coal burners (DF-CN burners, Figure 7) and a boundary air system (Figure 8) were applied to the No. 1 boiler in 1976 and to the No. 2 boiler in 1977.

As a third step, burners out of service (BOOS) and steam injection from oil guns were tested on the No. 2 boiler in 1978.

A fourth step to decrease NO_x emissions was based on the test results of the third step and the results on IHI's test facility (capacity of 2 ton/h pulverized coal firing). It was decided that the installation of eight

additional OAPs close to both side walls and a division wall (Figure 9) and installation of the steam injection nozzles on each oil burner gun would be carried out for No. 2 boiler. The target completion date was Spring 1979, aiming at NO_x reductions less than 160 ppm (at 6% O_2) under routine operation conditions. The same modifications were performed successfully on the No. 1 boiler in 1980. A summary of these countermeasures and the results are shown in Table X.

PRIMARY COMBUSTION CONTROL TEST

Figure 10 shows the relationship between TSC air ratio and NO_x level, and the predicted OAP damper open ratio for NO_x emissions less than 159 ppm. At 100% damper open ratio, TSC air is about 15% of total air volume.

Adapting these primary test results and results of IHI's test furnace to the Isogo power station, we predicted the NO_x level to be 150 ppm and below under the condition of 30% TSC air volume to total air volume.

RESULTS OF NO_x REDUCTION AFTER IMPROVEMENT OF COMBUSTION MODIFICATION

After installing OAP as illustrated in Figure 9, we had 190 ppm of NO_x as the upper level in normal operation and 150 ppm as the minimum level. At that time, boilers operating under routine conditions performed almost satisfactorily without slagging and fouling trouble.

However, when an NO_x emission level of 150 ppm is reached, superheater tube metal temperature increases beyond the recommended operating limit, and to protect the tubes, we have to restrict the two stage air volume (OAP air volume).

Figure 11 shows actual data for NO_x and indicates for increasing or decreasing load, NO_x levels seldom exceed 200 ppm. The predicted NO_x reduction was almost obtained. However, the increase in superheater tube temperature exceeded our expectations. Therefore, the achieved NO_x levels are normally less than 190 ppm.

UNBURNED MATERIAL

Other potentially serious problems accompanied NO_x reduction. These included an increase in CO, unburned solids in the fly ash, and increased

emissions of other hazardous organic materials such as P.O.M. In fact, these problems were recognized during the early stages of the field test runs.

To reduce the unburned material mentioned above, we have tried to improve the mixing conditions between the secondary staged air and the combustibles produced in the primary zone through the installation of additional OAPs.

By applying side OAPs, the remarkable NO_x reduction could be achieved while keeping unburned material at a constant level.

FUEL ANALYSIS

The fuel coal burned at Isogo Power Station is a blended variety, containing Taiheiyo coal as the main constituent. The typical analysis is shown in Table XI.

IMPROVEMENT OF SH TUBE TEMPERATURE AND SPRAY QUANTITY

To prevent the SH tubes from increasing in temperature, we modified the superheater layout, the final configuration of which is shown in Figure 12. In addition, the spray attemperation quantity was increased from 66 to 100 ton/hr. Currently, the spray quantity being employed is the same as that used before modifications for NO_x reduction. Unfortunately, the trend of high superheater temperatures is not remarkably improved.

Section 7

COMMERCIALIZED LOW NO_x BURNER FOR NEW COAL-FIRED POWER PLANTS

EPDC is constructing new coal-fired power plants such as the Matsushima power station and Takehara Unit No. 1. Each plant has incorporated NO_x combustion control technology developed with the aid of results from test furnaces.

MATSUSHIMA POWER STATION

Matsushima power station No. 1 unit is now performing trial operations until January 1981, and shortly thereafter, it will start commercial operation.

A description of the Matsushima power station is following:

- Output — 500 MW x 2 unit
- Fuel — Coal (imported)
- Boiler Manufacturer — MHI
- Type of Boiler — Supercritical pressure reheat type U.P. boiler
- NO_x (guaranteed) — 285 pm (O_2 = 6%) (N^2 = 1.7%)
- NO_x (target) — same as guaranteed
- Burner type — SGR burner (illustrated in Figure 13)

NO_x emission levels from the Matsushima power station are about 200 ppm (O_2 = 6%, N = 1.7%), measured after trial operation without burner adjustment or optimization.

COMPARISON OF NO_x EMISSIONS BETWEEN LABORATORY TEST RESULTS AND FIELD DATA

Figure 14 shows test furnace results and field data, the latter from EPDC's Takasago and Sunagawa of Hokkaido Electric Power Co.

We find good correlation between actual field data and test data using domestic coal, and therefore anticipate reducing NO_x emission levels to approximately 250 ppm (O_2 = 6%, N = 1.7%) as suggested by Figure 14.

TAKEHARA POWER STATION NO. 3

Construction has recently initiated on Takehara Unit No. 3 and commercial operation is scheduled for March 1983. An outline of Takehara No. 3 is as follows.

• Output	700 MW x 1 unit
• Fuel	Coal (imported coal)
• Boiler Manufacturer	BHK
• SCR Manufacturer	BHK
• Type of Boiler	B & W Supercritical pressure reheat type UP boiler
• NO_x (guaranteed at boiler)	250 ppm (O_2 = 6%, N = 1.8%)
• NO_x (target at boiler)	200 ppm (O_2 = 6%, N = 1.8%)
• NO_x (guaranteed at stack)	60 ppm and below (O_2 = 6%, N = 1.8%)
• Burner type	PG dual burner

The PG dual burner is shown in Figure 15.

COMPARISON OF NO_x EMISSION BETWEEN LABORATORY TEST RESULTS VS. FIELD DATA

Figure 16 shows the correlation between actual field data and test furnace data with heat release rate at the burner zone. This relation will be confirmed when Takehara No. 3 boiler is operating. EPDC anticipates achieving the target NO_x level.

REFERENCES

1. Y. Nakabayashi, Status of R&D on NO_x removal in Japan and results of EPDC's R&D for $DeNO_x$ Process. Second EPRI NO_x Control Technology Seminar, Denver Colorado, Nov. 1980.

2. Environmental White Paper, 1980, Japanese Environmental Protection Agencies.

Appendix A

Summary of Emission Control Research and Development in Japan for Coal-Fired Boilers

	Test Subjects	Location	Companies and Joint Researchers	Capacity	Fiscal 1975 (4 7 10 1)	1976 (4 7 10 1)	1977 (4 7 10 1)	1978 (4 7 10 1)	1979 (4 7 10 1)	1980 (4 7 10 1)	1981 (4 7 10 1)	Remarks
1. Desulfurization technology	(1) Soot separating desulfurization system (dust collecting)											
	a) Hitachi	Takehara Thermal Power Station	Hitachi	Approx. 2,000Nm^3/h								
	b) Mitsubishi	" "	Mitsubishi	"								
	c) IHI	Isogo Thermal Power Station	I H I	"								
	(2) Dry flue gas desulfurization system	Takehara Thermal Power Station	S H I I H I	10,000Nm^3/h								
2. Denitration technology	(Low Nox burner development test)											
	(1) Low NOx burner test	Takehara Thermal Power Station	Hitachi	Actual boiler			Test plant					Put into practical use (Dec. '75)
		Isogo Thermal Power Station	I H I	Actual boiler								Number of machines equipped(#1 Mar. '76) (#2 May '77)
	(2) Ultra-low Nox boiler test	Babcock Hitachi Kure Works	Hitachi	Test furnace								
		MHI Nagasaki Laboratory	Mitsubishi									
		IHI Aioi Works	I H I									

SUMMARY OF EMISSION CONTROL

RESEARCH PROJECTS FOR COAL FIRED BOILERS

Test Subjects	Location	Companies and Joint Researchers	Capacity	Fiscal 1975 (4 7 10 1)	1976 (4 7 10 1)	1977 (4 7 10 1)	1978 (4 7 10 1)	1979 (4 7 10 1)	1980 (4 7 10 1)	1981 (4 7 10 1)	Remarks
(3) 2-stage combustion device	Isogo, Takehara, Takasago	IHI, Hitachi, Mitsubishi	Actual boiler								Production type Isogo #1 Jul. '73 #2 Jun. '72 Takasago #1 Jul. '74 #2 Jun. '75 Takehara #1 Nov. '71
(Research and development of denitration technology)											
(1) SCR test											
a) Hitachi Shipbuilding & Engineering Co. (HZ)	Isogo Thermal Power Station	Hitachi Shipbuilding & Engineering Co.	Max. 250Nm^3/h and others								
b) I H I	"	I H I	Max. 1,000Nm^3/h and others								
c) Mitsubishi Heavy Industries (MHI)	Takasago Thermal Power Station	M H I	Max. 600Nm^3/h and others								
d) Hitachi	Takehara Thermal Power Station	Hitachi	Max. 2,300Nm^3 and others								
e) Kawasaki Heavy Industries (KHI)	"	K H I	Max. 4,000Nm^3/h and others								
(2) SNR test											
a) Coal ash effect confirmation test	Central Institut of Electric Power Industries (CRIEPI)	CRIEPI	Test furnace								
	Takasago Thermal Power Station	M H I	20Nℓ/min								
b) Boiler temperature measurement	Isogo Thermal Power Station	I H I	Actual boiler								

SUMMARY OF EMISSION CONTROL RESEARCH PROJECTS FOR COAL FIRED BOILERS
(Continued)

	Test Subjects	Location	Joint Researchers	Capacity	1975	1976	1977	1978	1979	1980	1981	Remarks
					4 7 10 1	4 7 10 1	4 7 10 1	4 7 10 1	4 7 10 1	4 7 10 1	4 7 10 1	
	(2) Denitration a) Air preheater test	Takasago Thermal Power Station	Gadelius	10,000Nm^3/h 5,000Nm^3/h								
		Takehara Thermal Power Station	HZ	2,000Nm^3/h								
		Isogo Thermal Power Station	I H I									
FGD Equipment for practical use												
(1) Isogo Thermal Power Station (#1)			I H I	265MWx2Units								#1 Unit (scheduled) to start up in MAR/76.
(#2)												#2 Unit (scheduled) to start up in MAY/76.
(2) Takasago Thermal Power Station (#1)			Mitsui Miike	250MWx2Units								#1 Unit (scheduled) to start up in FEB/75.
(#2)												#2 Unit (scheduled) to start up in MAR/76.
(3) Takehara Thermal Power Station (#1)			Hitachi	250MWx1Unit								Scheduled to start up in Feb./77
(4) Matsushima Thermal Power Station (#1)			I H I	500MWx1Unit								#1 Unit (scheduled) to start up in Dec./81. (3/4 Capacity)
(#2)			Hitachi	500MWx1Unit								#2 Unit (scheduled) to start up in Jul./81.

SUMMARY OF EMISSION CONTROL RESEARCH PROJECTS FOR COAL FIRED BOILERS
(Continued)

	Test Subjects	Location	Companies and Joint Researchers	Capacity	Fiscal 1975 (4 7 10 1)	1976 (4 7 10 1)	1977 (4 7 10 1)	1978 (4 7 10 1)	1979 (4 7 10 1)	1980 (4 7 10 1)	1981 (4 7 10 1)	Remarks
3. Dust Collecting Technology	(1) H. ESP	Isogo Thermal Power Station	S H I	10,000Nm^3/h								
		Takasago Thermal Power Station	Gadelius	5,000Nm^3/h								
		Takehara Thermal Power Station	Hitachi	2,300Nm^3/h								
		Isogo Thermal Power Station	I H I	2,000Nm^3/h								
		Takasago Thermal Power Station	M H I	900Nm^3/h								
	(2) Ditto. but test plant	Matsushima Thermal Power Station	S H I	500MWx1Unit								#1 Unit (scheduled) to start up in DEC/80.
			M H I	500MWx1Unit								#2 Unit (scheduled) to start up in JUL/81.
	(3) Bag filter	Not decided yet.	Not decided yet.	Not decided yet.								
4. Waste Water Treatment Technology	(1) Reverse osmosis process denitrification test	Isogo Thermal Power Station	S H I	Max.7m^3/day								
	(2) Biological treatment denitrification test	Manufacturer's laboratory	Mitsui Miike Ebara, HZ	Laboratory scale								
5. Attachment techniques	(1) Desulfurization											
	a) GGH test	Takasago Thermal Power Station	Gadelius	10,000Nm^3/h								
	b) De SOx fan test	Takehara Thermal Power Station	Hitachi M H I	10,000Nm^3/h								
	c) Corrosion-resisting material test	"	Fuji Resin	Test Piece								

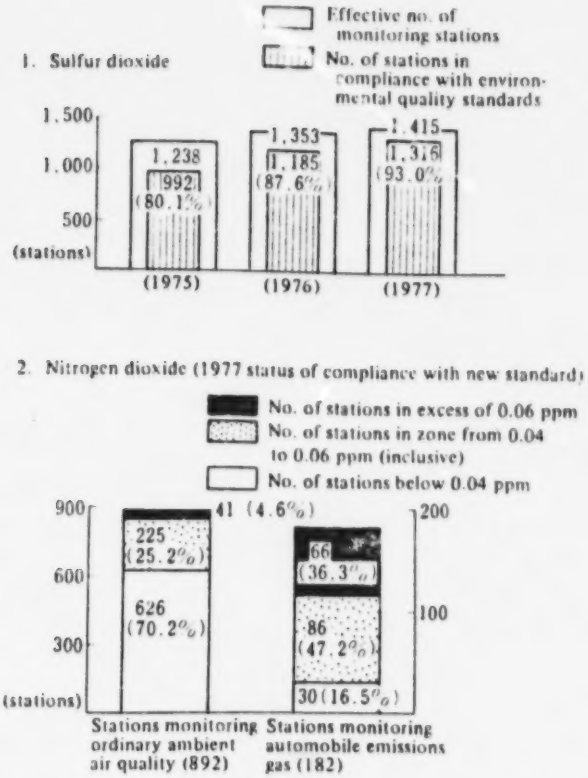
SUMMARY OF EMISSION CONTROL RESEARCH PROJECTS FOR COAL FIRED BOILERS
(Continued)

	Test subjects	Location	Companies Joint Researchers	Capacity	Fiscal 1975				1976				1977				1978				1979				1980				1981				Remarks
					4	7	10	1	4	7	10	1	4	7	10	1	4	7	10	1	4	7	10	1	4	7	10	1	4	7	10	1	
Denitration Technology Demostration Test		Takehara Thermal Power Station		800,000Nm³/h																													Entrusted by Government

SUMMARY OF EMISSION CONTROL RESEARCH PROJECTS FOR COAL FIRED BOILERS
(Concluded)

FIGURE I

STATUS OF COMPLIANCE WITH ENVIRONMENTAL QUALITY STANDARDS RELATING TO AIR POLLUTION

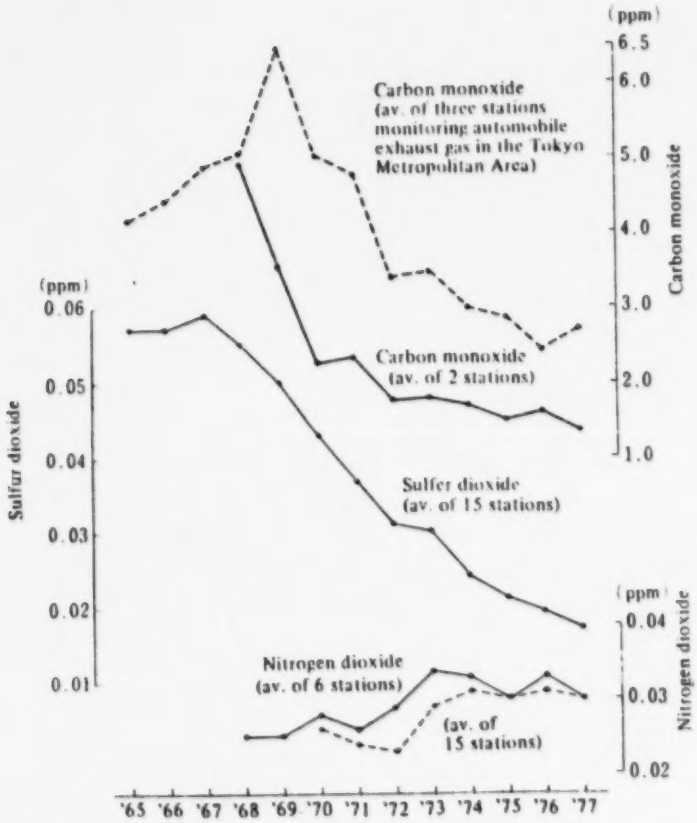


Notes: 1. Classified according to the annual 98 percentile value of daily average NO_2 concentration, with a Saltzman coefficient of 0.84.

2. Monitoring stations for automobile emissions situated over roadways have been excluded.

FIGURE 2

CHANGES IN THE ANNUAL DENSITY OF MAJOR AIR POLLUTANTS



Notes: 1. Carbon monoxide measurements by automobile exhaust gas monitoring stations are given in terms of calendar years.

2. Saltzman coefficient of 0.72 is used for nitrogen oxides.

Figure 3

Model Anti-pollution Coal-fired Thermal Power Plant

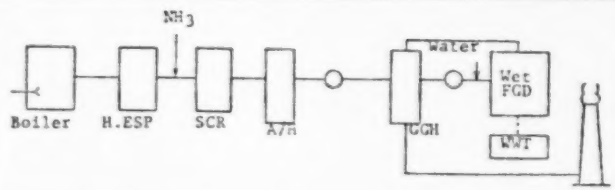
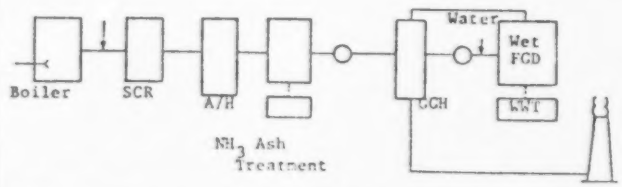
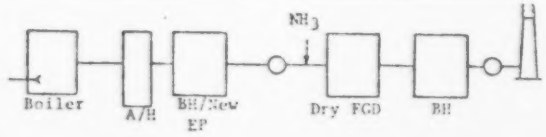
Case	System	Power Plant Flow	Con-centration	Remarks
1	Low Dust Denitration System		-	H.ESP: Hot-side Electrostatic Precipitator SCR: Selective Catalyst Reduction Equipment
2	High Dust Denitration System		-	A/H: Air Preheater GGH: Gas-Gas Heat Exchanger FGD: Flue Gas Desulfurization
3	Dry FGD System		-	W.WT: Waste Water Treatment Equipment BH: Bag House O: Fan

FIGURE 4

One Sample of Test Results

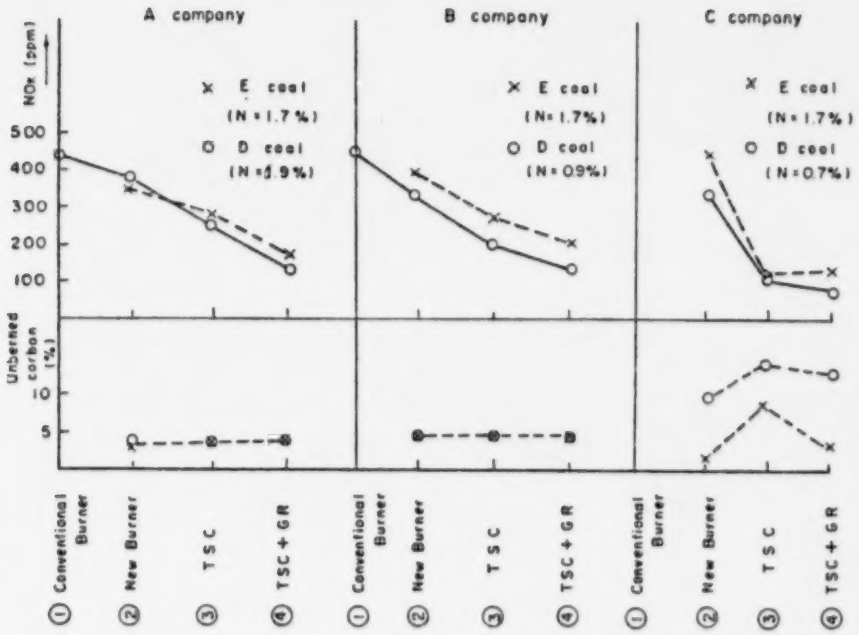
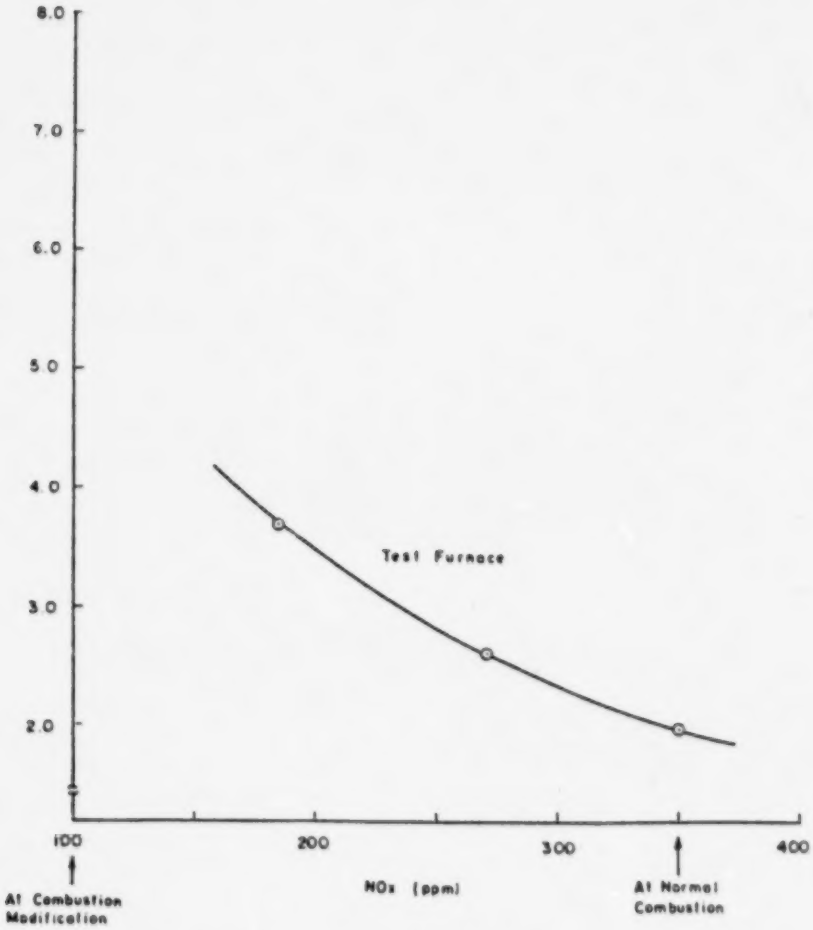


FIGURE 5

Corelation of NOx concentration vs P.O.M. Emission



NOx Concentration of Test Furnace is the average value of maximum and minimum values.

FIGURE 6

IHI'S ORIGINAL BURNER

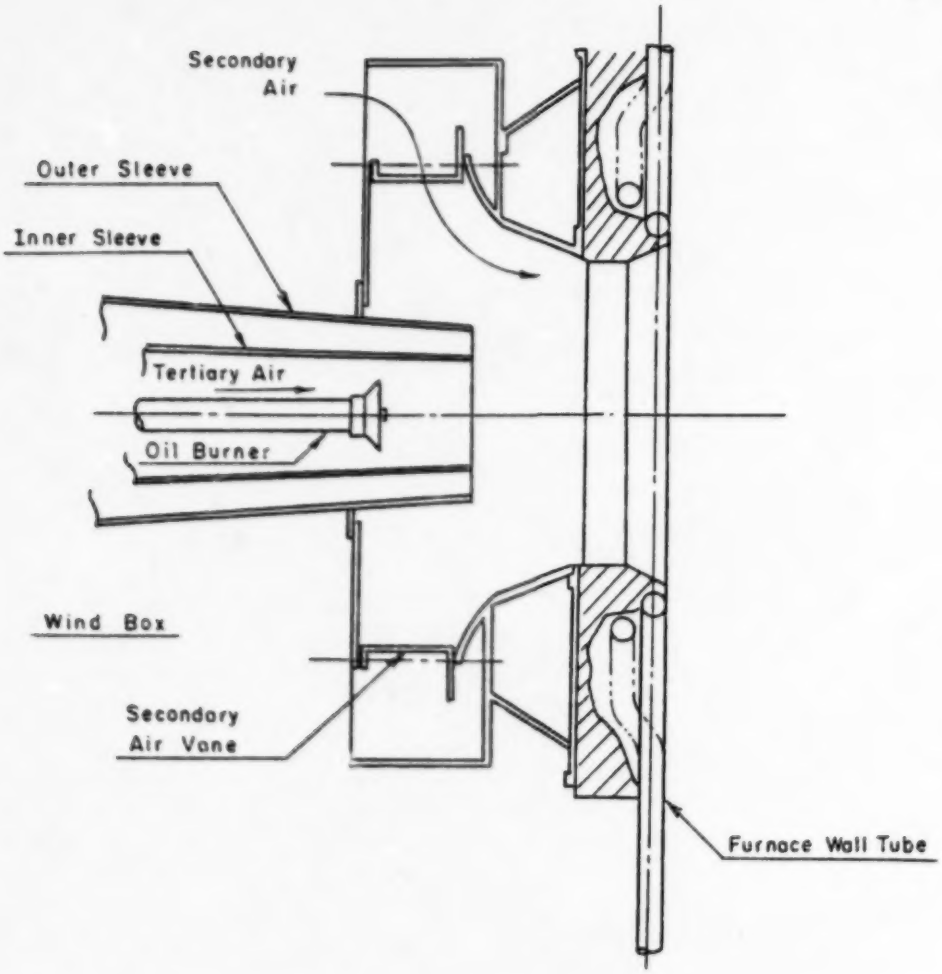


FIGURE 7

IHI'S DF-CN BURNER

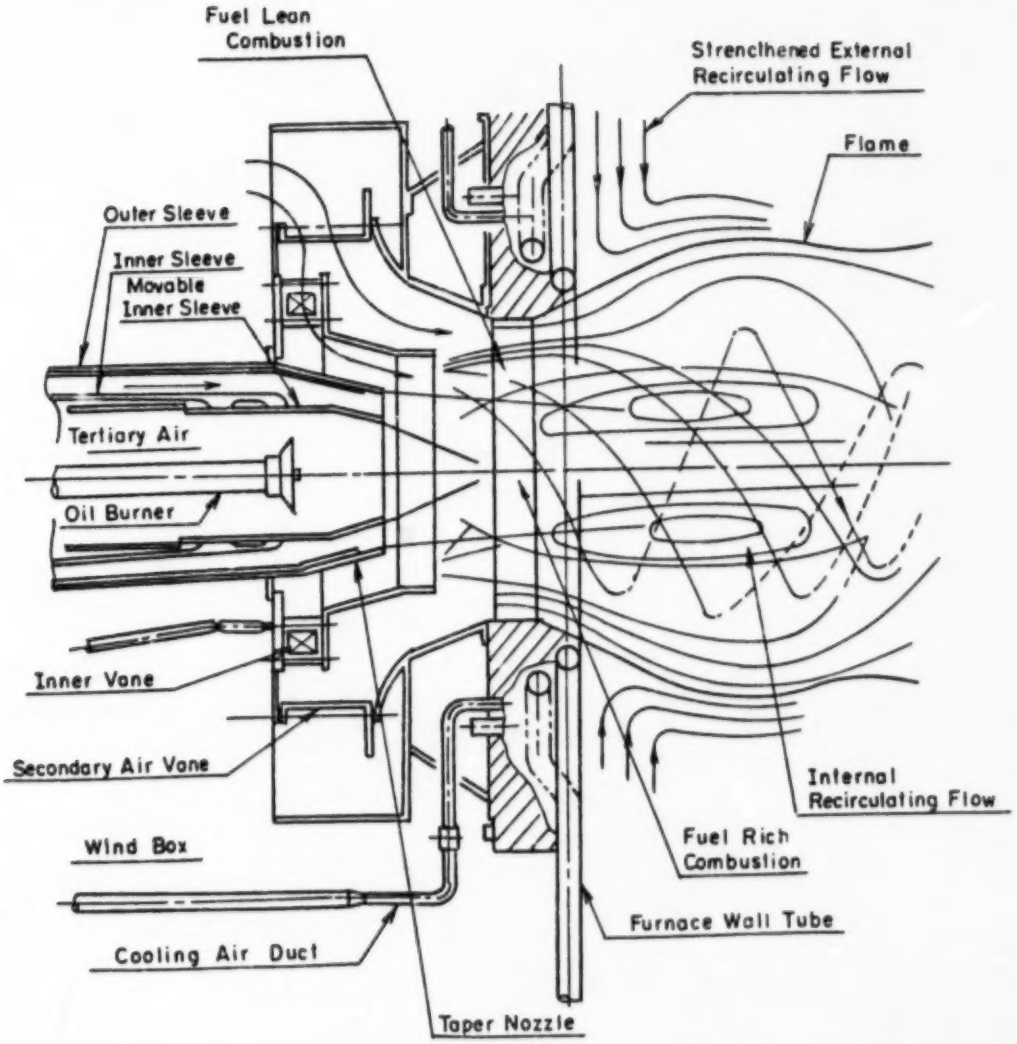
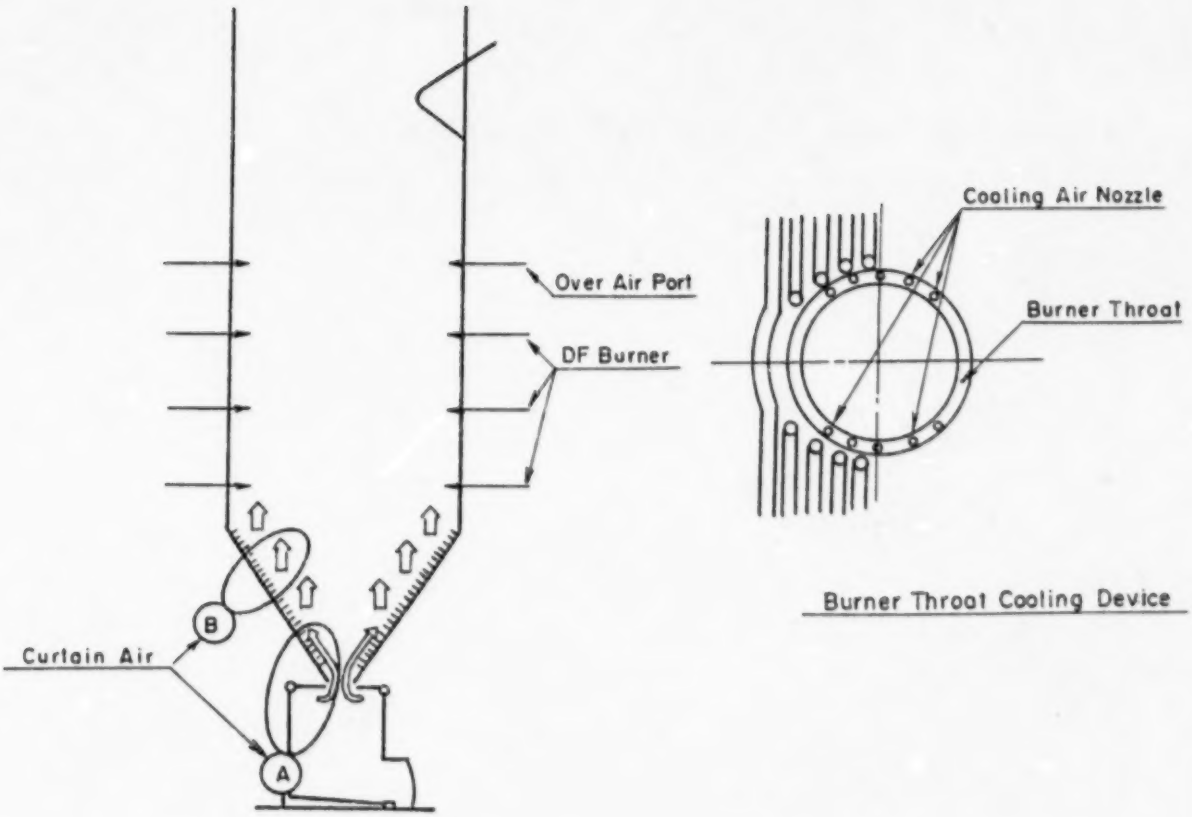


FIGURE 8

IHI'S BOUNDARY AIR SYSTEM



(Figure 9 omitted by author)

Fig.10 OAP Damper Open Ratio Versus NOx Emission

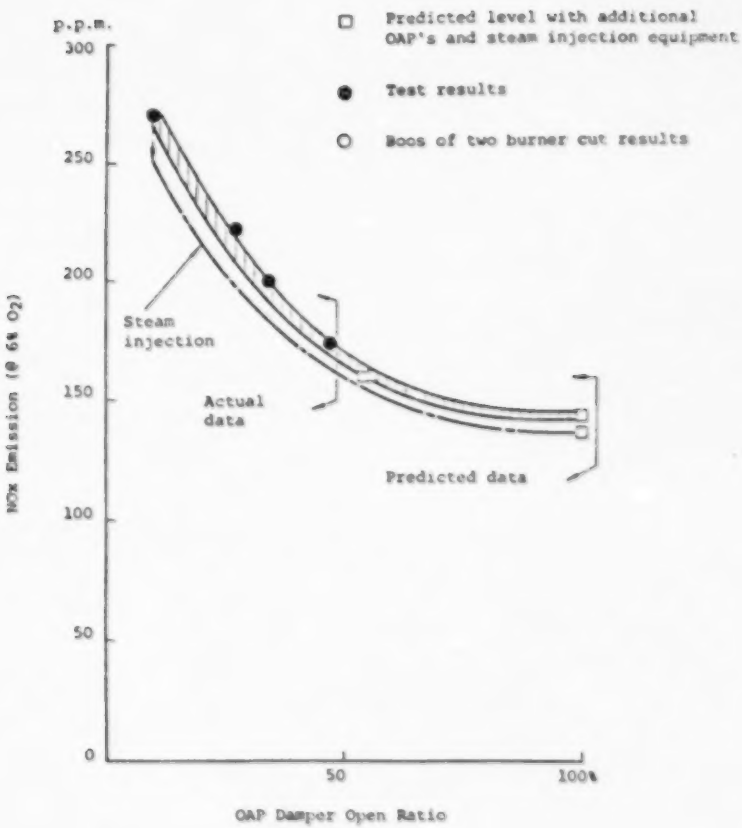


Figure 11 Actual Data of NOx

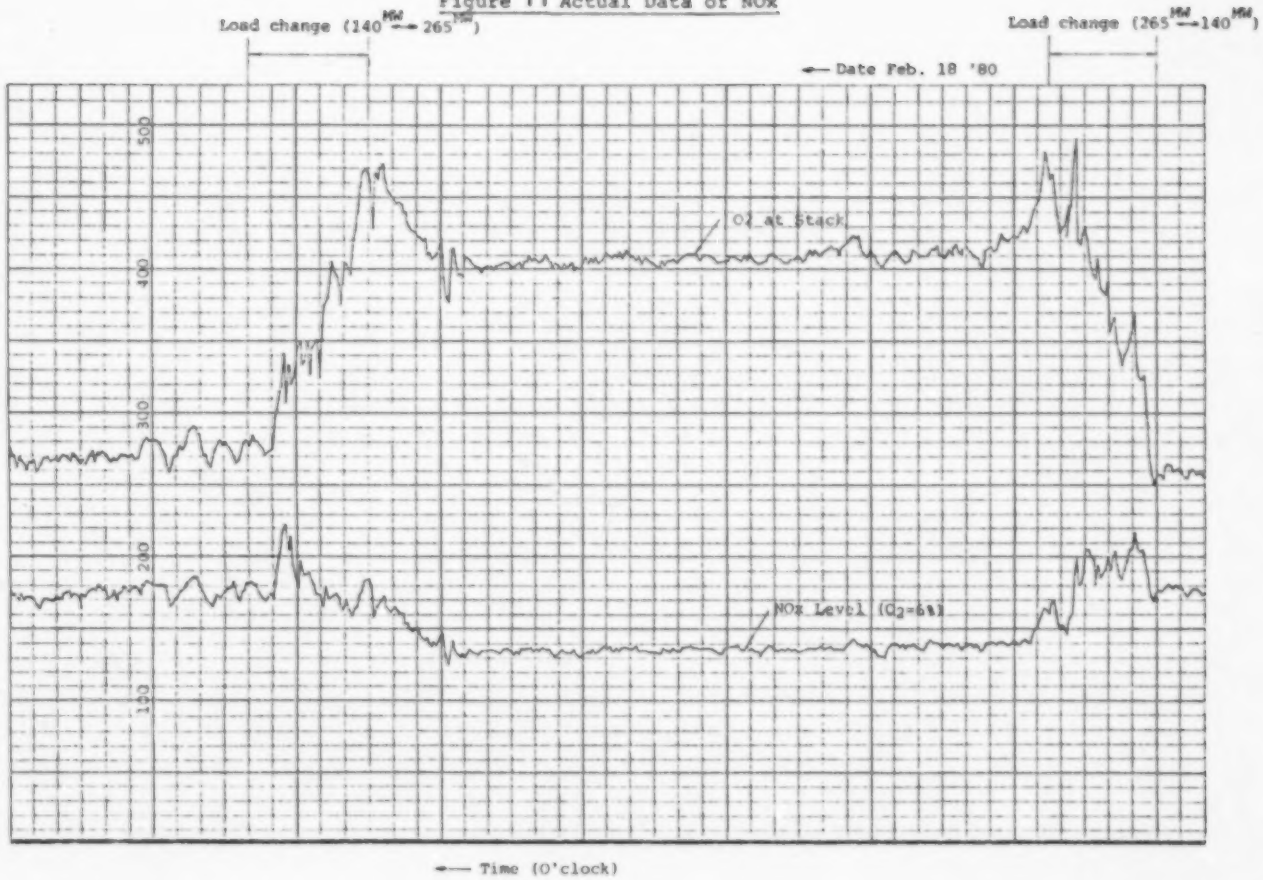
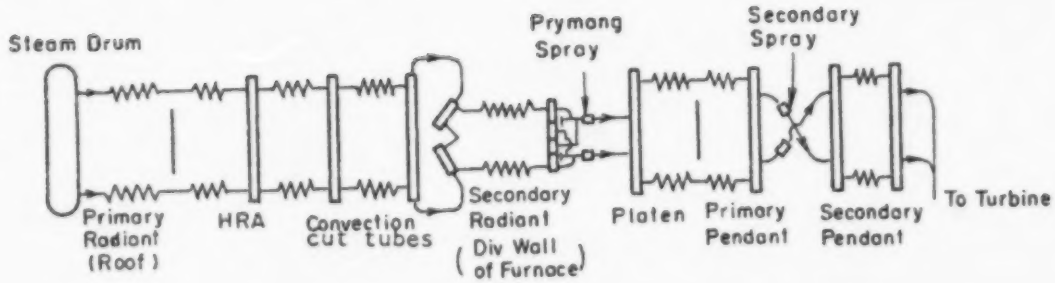


FIGURE 12

SH SYSTEM AND IMPROVEMENT



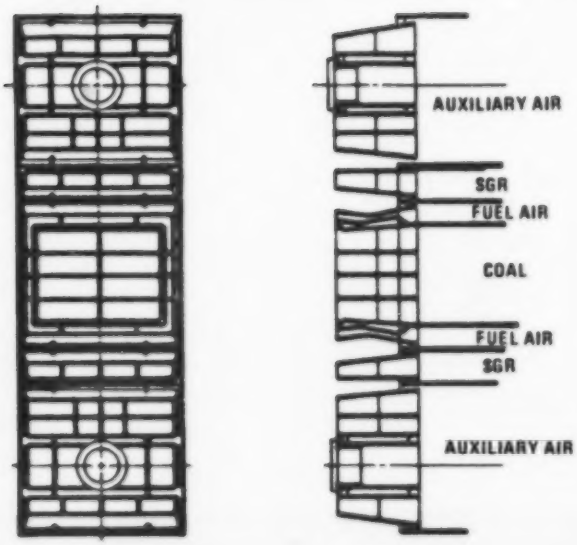


FIGURE 13

SGR Burner

FIGURE 14

Comparison of NOx Emission

- Laboratory Test Results vs. Field Data -

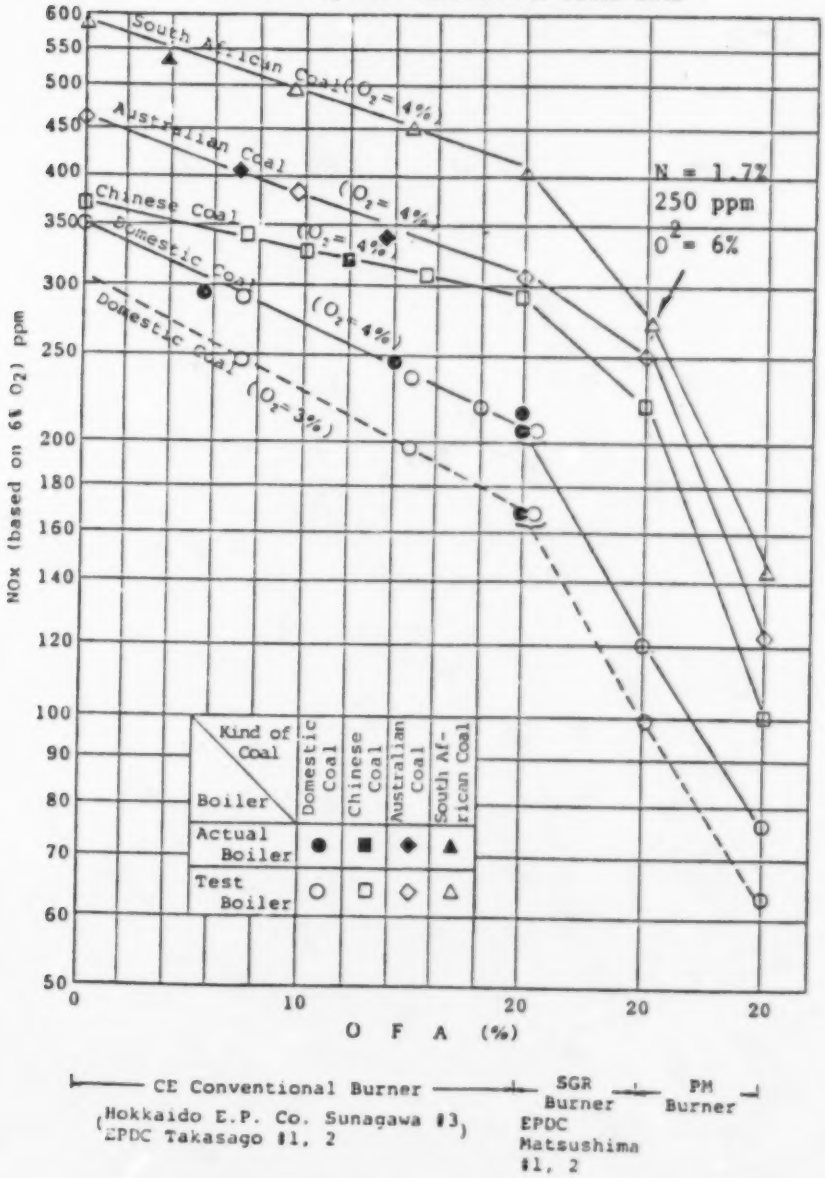


Figure 15 BHK Low NOx Burner

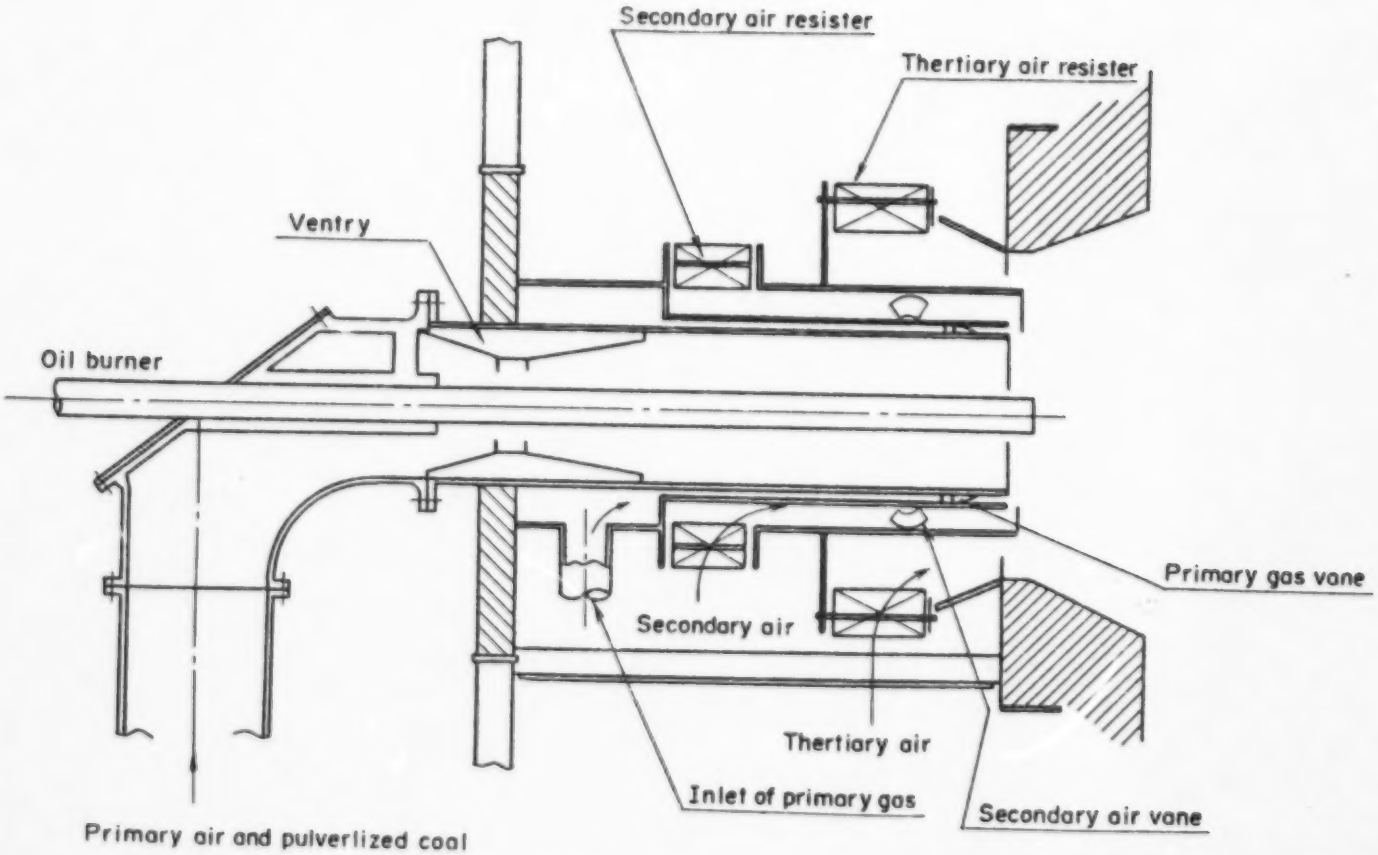


FIGURE 16

HEAT RELEASE RATE AT BURNER ZONE VS NOx LEVEL

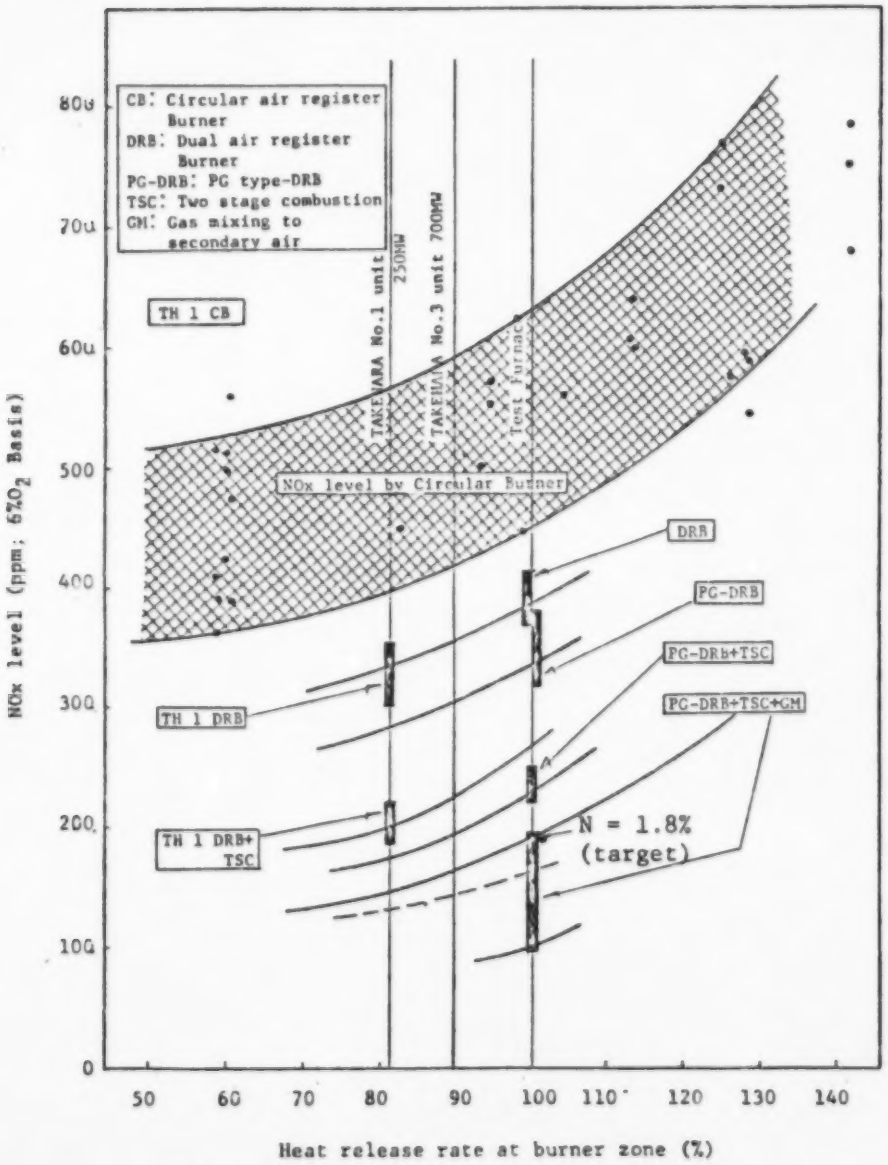


TABLE I

NO_2 ENVIRONMENTAL STANDARDS IN JAPAN

	NO_2 Environmental Standards announced as of May 8, 1973	NO_2 Environmental Standards revised as of July 11, 1978	Remarks
NO_2 high pollution areas	Intermediate target level: (effective through May, 1978) NO_2 level in the atmosphere should be less than 0.04 PPM on the hourly level. Final target value: (effective through May, 1981) NO_2 level in the atmosphere should be less than 0.02 PPM on the hourly level.	Final target level: (effective within seven years of the date of revision) NO_2 level in the atmosphere should be reduced to a range of 0.04 PPM to 0.06 PPM or less on the hourly average.	(1) The Japanese NO_2 Environmental Standards, which are much more rigid than those now in force in many foreign countries, have been disputed in Japan. (2) Nine per cent of the target level based on the original standards was attained as of fiscal 1976.
NO_2 low pollution areas	Final target value: (effective through May, 1978) NO_2 level in the atmosphere should be less than 0.02 PPM on the hourly level.		

TABLE 11

CHANGES OF NOx EMISSION STANDARD

(1st Standard Value : Aug. 10, 1973 start)
(2nd Standard Value : Dec. 10, 1975 start)
(3rd Standard Value : Jun. 18, 1977 start)

(Standard Valve ppm)

Scale of Facilities	Installation Time	Before Aug. 9, 1973			Aug. 10, 1973 ~ Dec. 9, 1975			Dec. 10, 1975 ~ Jun. 17, 1977		After Jun. 18, 1977	Notes
	Clarification of Restriction	1st Existing	2nd Existing	3rd Existing	1st New	2nd New	3rd Existing	2nd New	3rd Existing	3rd New	
	Applicable Time	From Jul. 1, 1975	From Dec. 1, 1977	From May. 1, 1980	From Aug. 10, 1973	From Dec. 1, 1977	From May. 1, 1980	From Oct. 10, 1977	From May 1, 1980	From Jun. 18, 1977	
Gas Firing (O_2 : 5%)	million 0.5 Nm^3/h over	170	130	130	130	130	130	100	100	60	
	million 0.1 ~ 0.5	170	130	130	130	130	130	100	100	100	
Solid Firing (O_2 : 6%)	million 0.1 over	600 (750)	600 (750)	480	480	480	480	480	480	400	( ) indicates combustion with low calorific value coal (5,000 Kcal/kg under) ∴ Ceiling burner 650 ppm Devided wall type 550 ppm
Fluid Firing (O_2 : 4%)	million 1 over	230 (280)	230 (280)	180	180	180	180	150	150	130	( ) indicates combustion with crude oil and tar
	million 0.5 ~ 1	230 (280)	230 (280)	180 (210)	180	180	180	150	150	130	[ ] indicates plant equipped with DeSOx system
	million 0.1 ~ 0.5	230 (280)	230 (280)	190 (210)	130	180	180	150	150	150	

Table III
Present State of NOx Emission Control
for Existing Coal Fired Boiler

		Isogo P.S	Takasago P.S	Takehara P.S #1 unit
Law		400	400	400
Ordinances agreement		151 (under negotiatun)	300	410
Refferences	Output	265MW x 2	250MW x 2	250MW x 1
	Fuel	coal	coal	coal
	N content	1.1	1.0	1.0

Table IV
Sample of NOx Emission Control
for New Coal Fired Boilers

	Matsushima P.S	Takehara P.S			
Law (O_2=6%)	400 ppm	400 ppm			
Ordinances agreement (O_2=6%)	300 ppm		No.1	No.2	No.3
		1980	—	—	—
		1982	112	175	60
		1983	79	175	60
		1984	72	115	60
		1987	60	81	54
Remarks			250MW	350MW	700MW
			coal	oil	coal

TABLE V

NOx REDUCTION PROGRAM

IN TAKEHARA AREA

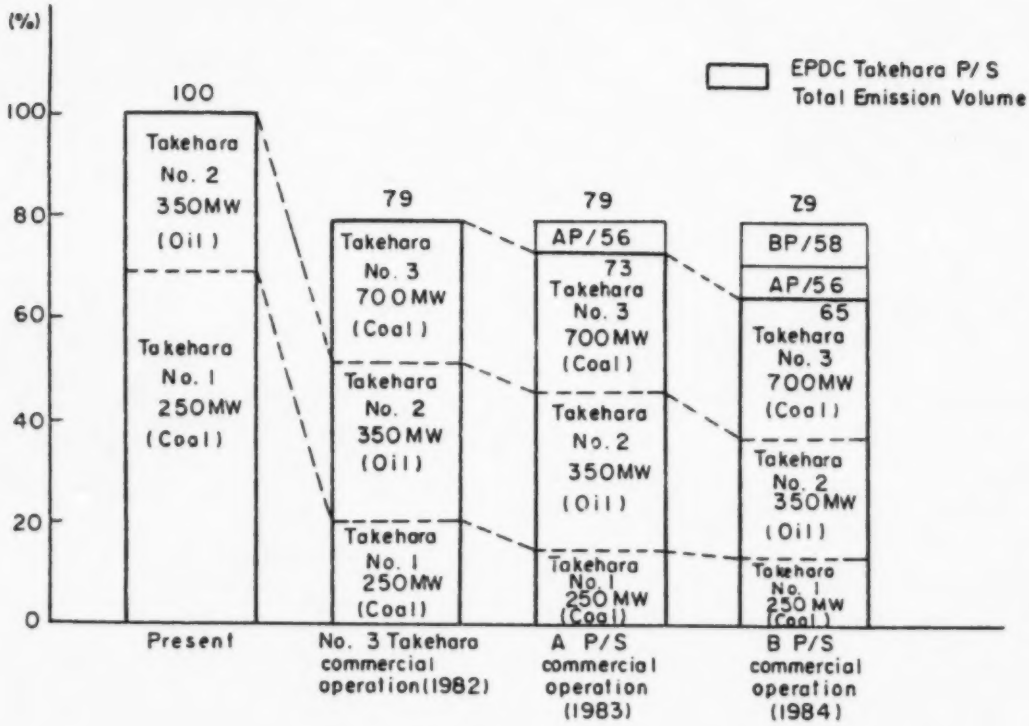


TABLE VI

Nitrogen Content of Planning Coal

China	A	B
N (%)	1.4	0.8

Australia	A	B	C	D	E	F	G	H	I
N (%)	1.6	1.7	1.6	1.5	1.6	1.6	1.5	1.6	1.7

The others	A	B	C-1	C-2	C-3	D
N (%)	1.8	1.7	1.6	1.4	1.4	1.42

Domestics	A	B
N	0.8	1.0

316
525

TABLE VII

Outline of R & D Programs on Combustion NOx Control Techrology

	Test Location	Test furnace Capacity	Test conditions	Soheduled				
				1977	1978	1979	1980	1981
MHI	Nagasaki	1.3 kl/H (oil base)	TSC, GRF, GM, SGR & PM burner					
BHK	Kure	2.0 t/H (coal base)	TSC, GRF, GM, PG burner					
IHI	Aioi	1.0 t/H (coal base)	TSC, GRF, DF (E) burner					
KHI	Shiga	3.7 t/H (coal base)	TSC, GRF, GM V-D burner					

TSC : Two Stage Combustion

GM : Gas Mixing

Table VIII

Measurement Results of P. O. M. at Furnaces

Unit ug / Nm^3

P. O. M. Component \ Combustion Condition	Normal Combustion	2 stage Combustion	2 stage + FG mix + Primary Gas	PGM	Partial Load
Naphthalene	0.22	0.18	0.22	0.24	0.24
Fluoranthene	-	0.40	0.88	0.78	0.84
Pyrene	0.65	0.64	0.87	0.87	0.84
Benzo (a) pyrene	0.48	0.59	0.66	0.58	0.62
Total P. O. M.	1.99	2.62	2.46	3.15	3.49
(Percentage when Normal combustion is 100)	(100)	(132)	(124)	(158)	(175)

TABLE IX. SUMMARY OF ISOGO 265 MW PULVERIZED COAL FIRED BOILER (NO. 1 and NO. 2)

Type	:	IHI-FW single drum, radiant type, natual circulation, reheat boiler (Indoor service)
Evaporation (at M.C.R.)	:	840,000 kg/h
Steam pressure (at M.C.R.)		
Superheater outlet	:	176 kg/cm^2g
Reheater outlet	:	34 kg/cm^2g
Steam temperature (at M.C.R.)		
Superheater outlet	:	571°C
Reheater outlet	:	571°C
Fuel	:	Bituminous coal (Equipped with 50% MCR heavy oil firing system)
Number of burner	:	24 set (4 rows and 3 stages on boiler front and rear walls)
Draft System	:	Balance draft system

TABLE X Countermeasure for NOx Control for Isogo Power Station NO.2 Unit

Month. Year	NOx Emission Level by Regulation, etc. (ppm)	Achieved NOx Level (ppm)	Countermeasure
Before May, 1973	600	570	None
June, 1973	600	380 ∿ 510	Two Stage Combustion
Apr., 1977	480	240 ∿ 250	Low NOX Burner Curtain Air
Apr., 1979	400	170 ∿ 190	Strength of Two Stage Combustion, etc.
Apr., 1980	159* Yokohama city's Requirement	170 ∿ 190	

TABLE XI

TYPICAL ANALYSIS ISOGO'S COAL

Higher heating value	6,200 kcal/kg
Ash	16.5%
Volatile matter	39.6%
Fixed carbon	39.4%
Sulfur	0.4%
Hydrogen	5.5%
Nitrogen	1.0%